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by

James R. Melcher and Peter Zieve

Energy Laboratory Report No. MIT-EL 79-017
November 1979

STUDY OF NEW ENGLAND UTILITIES' PARTICULATE AIR POLLUTION CONTROL FACILITIES TO DETERMINE RELATIVE VIABILITY OF APPROACHES TO UPGRADE AND RETROFIT

by

James R. Melcher
and
Peter Zieve

Massachusetts Institute of Technology
Cambridge, Massachusetts 02139

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STUDY OF NEW ENGLAND UTILITIES' PARTICULATE AIR POLLUTION CONTROL FACILITIES TO DETERMINE RELATIVE VIABILITY OF APPROACHES TO UPGRADE AND RETROFIT

EXECUTIVE SUMMARY

The goals of this study are to define the air pollution control requirements of the sponsoring utilities over a ten year period and investigate the extent to which selected innovative particulate control technologies can contribute to meeting these requirements. Scenarios are developed which describe the air pollution control requirements of five facilities selected from those owned by the sponsoring utilities, and the use of innovative technologies as retrofits is investigated for each.

According to the Clean Air Act, emissions from existing facilities are regulated by state environmental authorities. The Clean Air Act dictates that state permit levels must be set such that ambient air quality standards are achieved. Ambient air quality standards are set by the EPA Administrator and he is directed under the Clean Air Act to continually update these standards to reflect new health and environmental data.

The particulate ambient air quality standard presently is blind to particle size and toxicity. Proposals for ambient inhalable and fine particulate standards are presently under study at EPA. The inhalable standard would account for particles smaller than 15 μm in diameter, and as presently proposed will allow the ambient standards to be more easily achieved. A fine particle standard would account for particles smaller than 2.5 μm in diameter, and has been proposed for enactment in 1985. Proposed levels for a fine particle standard have not yet been announced by EPA, consequently it is difficult to speculate on the impact which this standard will have on the utility industry. A fine particle emission standard is hypothesized in the study to facilitate evaluation of the selected innovative technologies.

The recently enacted Powerplant and Industrial Fuel Use Act gives the Secretary of Energy discretionary power to prohibit certain classes of existing powerplants from burning oil. Under the Fuel Use Act new facilities must employ coal or another alternate fuel as defined in the act. The emission limitations for new facilities are set by the federal new source performance standards, which in the case of utility steam generators, have just recently been revised.

Six innovative technologies are chosen from a review of available literature according to their potential for solving utility emission problems. The six technologies are each identified with a particular development group, since they range from bench scale to commercialized in their development, more documentation is available for some than others. The electrofluidized bed under development at MIT collects particulate in a fluidized bed of granules across which an electric field is applied. The Electrified Bed under development at EFB, Inc. collects pollutant in a panel bed of granules across which an electric field is applied. In conjunction with the spray dryer technology the Electrified Bed is presently under development for simultaneous collection of particulate and SO_2. The high intensity ionizer, which until recently was promoted by Union Carbide, enhances the efficiency of a conventional electrostatic precipitator by intensely charging particulate at the precipitator inlet. The electrostatically enhanced bag filter manufactured by Apitron reduces the pressure drop and improves the collection efficiency of a conventional fabric filter through charging the particulate just before it reaches the bags. The wet electrostatic precipitator manufactured by Fluid-Ionic uses concentric cylinders as precipitator collection plates in the upper half of the collector with a cyclonic wet scrubber in the lower half of the collector. The use of the Fluid Ionic wet scrubber for SO_2 collection has been proposed and tested under EPA contract, but not commercialized. The charged droplet scrubber is under development at the University of Washington. In this device, water droplets and particulate are charged to opposite polarity. The use of water droplets for simultaneous particulate and SO_2 control has been tested under EPA contract.

The six technologies are assessed for use at each facility, and for those which appear attractive, a preliminary layout into the plant flue stream is performed. Table 5.4 a,b reviews the preliminary conclusions reached from the matchings of innovative technologies to the five plants. To the extent of available data a capital and operating cost on a dollar per acfm basis is assigned to both innovative and conventional approaches for solving each plant's requirements. Problem areas and development requirements are also discussed as they apply to the employment of each technology.

Mt. Tom of Northeast Utilities is a nameplate 136 MW generating station which has been in service since 1960. The unit presently burns 1%S oil but originally burned coal and is equipped with a multiclone and an electrostatic precipitator of approximately 75 ft^2/1000 acfm SCA. The primary scenario for this facility is a prohibition from oil firing under terms of the Fuel Use Act. If a conversion order is issued under the Fuel Use Act the facility will remain subject to the state emission standard of 1.21 lb/MMBtu for SO_2 emissions and .12 lb/MMBtu for particulate emissions. This standard would be difficult to achieve without the use of SO_2 scrubbing. The agreement permitting the use of 1.5%S coal at Brayton Point serves as a guide for a conversion plan which could be employed at Mt. Tom. Under this plan the precipitator SCA would have to be increased in size to approximately 300 ft^2/1000 acfm. Two innovative technologies investigated for use in the place of additional ESP volume are the electrofluidized bed collector and the Electrified Bed.

Middletown 3 of Northeast Utilities is a 240 MW cyclonic fired boiler which was originally put in service on coal firing in 1964, and converted to oil firing in February 1967. The high cost of coal conversion for this facility makes the issuance of a prohibition from oil firing unlikely. The primary scenario for this facility is a requirement for an enhanced fine particle collection efficiency. The electrofluidized bed agglomerator and the Electrified Bed are investigated for use on the new facility.

Mystic 7 of Boston Edison is a tangentially fired 580MW facility put on line for oil firing in 1975. The 340 ft^2/1000 acfm SCA electrostatic precipitator reduces the emission rate from this facility to a level well below that required to achieve the state emission standard, and generally in compliance with the .03 lb/MMBtu new source performance standard. If a similar facility was built today coal firing would be employed, and compliance with the new source performance standards would be required. The two-stage electrofluidized bed collector, the one-stage Electrified Bed, the Electrified Bed in conjunction with a spray dryer for SO_2 control system and the charged droplet scrubber are investigated for use on this facility.

Brayton Point 2 of New England Electric is a 252MW tangentially fired boiler originally put in service on coal firing in 1964. Under the auspices of ESECA a coal conversion plan was negotiated between New England Electric and government officials. Brayton Point 2 is slated to resume coal firing in 1983. The coal conversion plan calls for the use of 1.5%S coal without the employment of SO_2 scrubbing. In order to achieve the .08 lb/MMBtu mandated emission standard with a wide safety margin present plans call for the SCA of the present electrostatic precipitator to be enlarged from the present 187 ft^2/1000 acfm through the installation of an additional electrostatic precipitator in series of almost double the present size. The electrofluidized bed, the Electrified Bed, and the high intensity ionizer are investigated for employment in the place of additional ESP volume.

New Boston 2 of Boston Edison is a pressurized 380 MW facility put in service on oil firing in 1967. The unit is designed to accomodate coal firing, but equipment essential for coal combustion has not been purchased. Although Edison personnel do not believe that coal combustion is an attractive alternative for New Boston at this time, provisions of the Fuel Use Act could force this issue, in which case pollution control equipment would be required to achieve the state emission standards of .55 lb/MMBtu for SO_2 and .12 lb/MMBtu for particulates. The unit presently is not equipped with pollution control equipment, and the original design called for a small electrostatic precipitator to be installed on a platform cantilevered from the boiler support structure. The two-stage electrofluidized bed, the Electrified Bed in conjunction with the spray dryer SO_2 control system, and the wet electrostatic precipitator for combined particulate and SO_2 control are investigated for use on this facility.

TABLE ES 1a Listing of Innovative Technologies Suitable for Individual Plant Requirements

Technologies \ Plants	Mt. Tom	Middletown 3	Mystic 7
Electrofluidized Bed Collector	Yes, downstream from the present electrostatic precipitator	No, insufficient space available.	Yes, two-stage collector required. No SO_2 control provided.
Electrofluidized Bed Agglomerator	No, insufficient space available.	Yes, upstream from the present electrostatic precipitator.	No, not appropriate since technologies are here considered for replacement rather than retrofit.
Electrified Bed	Yes, one-stage collector incorporated into the present ESP exit plenum.	Yes, a one-stage collector incorporated into the present ESP exit plenum.	Yes, two-stage collector with spray dryer to provide combined particulate and SO_2 control.
High Intensity Ionizer	No, ESP facial velocities too high.	No, ESP facial velocities too high.	Yes, in conjunction with electrofluidized and one-stage Electrified Beds.
Electrostatically Enhanced Bag Filter	No, insufficient space available, preferentially a replacement technology.	No, insufficient space available, preferentially a replacement technology.	Yes, could provide simultaneous SO_2 control with spray dryer alkali injection.
Wet Electrostatic Precipitator	No, wet collection not desirable in lieu of requirement for FGD.	No, wet collection not desirable in lieu of requirement for FGD.	No, not sufficiently efficient to achieve particulate NSPS standard.
Charged Droplet Scrubber	No, wet collection not desirable in lieu of requirement for FGD.	No, wet collection not desirable in lieu of requirement for FGD.	Yes, to provide simultaneous particulate and SO_2 control.

TABLE ES 1b Listing of Innovative Technologies Suitable for Individual Plant Requirements

Plants / Technologies	Brayton Point 2	New Boston 2
Electrofluidized Bed Collector	Yes, downstream from the present electrostatic precipitator.	Yes, two-stage collector required. No SO_2 control provided.
Electrofluidized Bed Agglomerator	Yes, upstream from the present electrostatic precipitator,	No, not appropriate for unit without pollution control equipment presently in place.
Electrified Bed	Yes, one-stage collector incorporated into present ESP exit plenum.	Yes, two-stage collector with spray dryer to provide combined particulates and SO_2 control.
High Intensity Ionizer	Yes, incorporated into the present ESP inlet plenum.	Yes, in conjunction with the electrofluidized bed collector.
Electrostatically Enhanced Bag Filter	No, insufficient space available.	No, insufficient space available.
Wet Electrostatic Precipitator	No, wet collection not desirable because FGD not required for the unit.	Yes, to provide combined wet SO_2 and particulates control.
Charged Droplet Scrubber	No, wet collection not desirable in lieu of requirement for FGD.	No, insufficient space available.

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I. LEGISLATIVE IMPACTS ON UTILITY OPERATIONS

The legislative research was included as a part of the study of New England Utilities for two reasons. First, it was proposed as a useful study to the sponsoring utilities to have present and proposed laws reviewed and analyzed through the eyes of researchers in the area of particulate control. Second, the legislative study provides guidance to the hardware aspect of the study, for hardware must be picked and sized with respect to particular environmental constraints. It is pointless to pick hardware for installation on a ten-year time scale according to present environmental constraints, if these very constraints are changing at a faster rate than the technology. A third reason, internal to the research effort at MIT, is to help guide our work toward real rather than simply hypothetical demands of society. Hopefully, the study will have a similar influence on the research efforts of others.

By necessity, the legislative survey is done through the eyes of a reporter. Accordingly, an extensive bibliography accompanies this section and opinions are stated as such. The legislative survey is intended to help predict the direction in which legislation is heading, and should not act as an editorial on the way in which laws should head.

A. Introduction

1. The Clean Air Act and Federal vs. State Authority

The first federal law dealing with the problem of air pollution was enacted in 1955 and entitled, "Air Pollution Control--Research and Technical Assistance." [1] The Senate report on the legislation contained the following language:

> The Committee recognized that it is primarily the responsibility of state and local governments to prevent air pollution. The bill does not provide any exercise of police power by the federal government and no provision in it invades the sovereignty of states, counties, or cities. There is no attempt to impose standards of purity.

In the fifteen-year period from when this first federal funding bill was enacted, the federal role grew from the conservative stance reflected above to the 1970 Clean Air Amendments which have put the federal government in the driving position in the push toward clean air.

Even within that fifteen year period, the federal role became significant only toward the latter years. The Clean Air Act of 1963 provided grants to states conducting air quality programs, and in addition authorized the HEW to publish nonmandatory air criteria and authorized HEW intervention in cases where air pollution threatens to endanger "health and welfare". The '65 amendments authorized the HEW to enforce automotive emission standards and allowed the HEW Secretary to intervene in cases of international air pollution. The '67 amendments permitted the HEW Secretary to issue mandatory air quality criteria within an Air Quality Control Region (AQCR).

The 1970 Clean Air Act introduced the air pollution control structure still in force today. The federal administrator is responsible for issuing a set of National Ambient Air Quality Standards (NAAQS) which are designed to protect both the health and welfare of the population. State control agencies are authorized to control emission sources within their states through a State Implementation Plan (SIP). The SIP outlines the state program for achieving the NAAQS. This plan, to be approved by the EPA must provide for emission limitations, monitoring of stationary sources, and for new sources, must incorporate a permit system. Section 110 (a)(2) of the Clean Air Act states with respect to the SIP:

> (B) it includes emission limitations, schedules, and timetables for compliance with such limitations, and such other measures as may be necessary to insure attainment and maintenance of such primary or secondary standard, including, but not limited to transportation controls, air quality maintenance plans, and preconstruction review of direct sources of air pollution as provided in subparagraph (D);
>
> (C) it includes provision for establishment and operation of appropriate devices, methods, systems, and procedures necessary to (i) monitor, compile, and analyze data on ambient air quality and, (ii) upon request, make such data available to the Administrator;
>
> (D) it includes a program to provide for the enforcement of emission limitations and regulation of the modification, construction, and operation of any stationary source, including a permit program for any major emitting facility, within such region as necessary to assure (i) that national ambient air quality standards are achieved and maintained, and (ii) a procedure, meeting the requirements of paragraph (4), for review (prior to construction or modification) of the location of new sources to which a standard of performance will apply;

Other regulations concerning the SIPs are contained in Section 110 of the CAA and Part 51, Title 40, of the Code of Federal Regulations. These regulations stipulate that if a state does not submit an appropriate plan to the

EPA, the EPA must draft and promulgate an appropriate plan. Approval and promulgation of state plans is detailed in Part 52, Title 40, of the Code of Federal Regulations. If a state does not properly enforce the provisions of its SIP, the Administrator of EPA under Section 113 of the CAA is authorized, after suitable notification, to enforce the provisions of the plan. In addition, economic motivations in the form of federal grants are given to states submitting appropriate plans. The CAA authorizes the EPA to limit licensing of new sources in area not achieving the NAAQS by a set date. This last provision, which would freeze state economic growth, has provided a strong incentive for states to adopt and enforce appropriate state air laws.

The federal involvement for new sources is even more direct. Section 111 of the CAA instructs the Administrator to promulgate regulations which would dictate that all new sources adopt:

> ...the degree of emission reduction achievable through the application of the best system of continuous emission reduction which the Administrator determines has been adequately demonstrated for that category of sources.

These paragraphs have attempted to demonstrate the rapid growth of air regulation, almost entirely motivated through Congressional exercise of the Commerce clause, which has occurred since 1970. These regulations have, and will continue to have a significant impact on utility operations, The following subsections of this chapter will attempt to outline how various provisions of the law, i.e., SIPs, NAAQS, NSPS, affect utility air pollution requirements today and in the foreseeable future.

B. Legislation

1. National Ambient Air Quality Standards

a. Present

The national ambient air quality standards (NAAQS) are set by the Administrator of EPA under the authority of Sec. 109 of the Clean Air Act (42 U.S.C. 7411). The attainment of the NAAQS is the primary criteria by which state implementation plans (SIP) are evaluated, and therefore have a major effect on air pollution regulations.

Section 109 (b)(1) of the CAA states:

> National primary ambient air quality standards, prescribed, under subsection (a) shall be ambient air quality standards the attainment and maintenance of which in the judgement of the Administrator, based on such criteria and allowing an adequate margin of safety, are requisite to protect the public health. Such primary standards may be revised in the same manner as promulgated.
>
> (2) Any national secondary air quality standard prescribed under subsection (a) shall specify a level of air quality the attainment and maintenance of which in the judgement of the Administrator, based on such criteria, is requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air. Such secondary standards may be revised in the same manner as promulgated.

As of February, 1979 the NAAQS are listed in Table 1.1.

The primary standard is purely health based, and does not allow the administrator to consider non-health criteria, such as economic effects in the standard setting. The secondary standard is designed to protect the public welfare, is typically equal to or stricter than the primary standard, and inherently permits a balance between health, economic, and aesthetic

TABLE 1.1

National Ambient Air Quality Standards

POLLUTANT	PRIMARY STANDARDS	AVERAGING TIME	SECONDARY STANDARDS
Carbon Monoxide	10mg/m^3	8-hour*	same as primary
	40mg/m^3	1-hour*	
Hydrocarbons (Non-Methane)	160 $\mu g/m^3$	3-hour* (6 to 9 am)	same as primary
Lead	1.5 $\mu g/m^3$	quarterly average	same as primary
Nitrogen Oxides (NO_2)	100 $\mu g/m^3$	Annual (arithmetic mean)	same as primary
Particulate Matter	75 $\mu g/m^3$	Annual (Geometric Mean)	60 $\mu g/m^3$
	260 $\mu g/m^3$	24-Hour	150 $\mu g/m^3$
Ozone	235 $\mu g/m^3$	1-Hour**	same as primary
Sulfur Oxides (SO_2)	80 $\mu g/m^3$	Annual (Arithmetic Mean)	---
	365 $\mu g/m^3$	24-hour*	---
	---	3-hour*	1300 $\mu g/m^3$

*Not to be exceeded more than once a year.

** The standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 235 $\mu g/m^3$ is equal to or less than 1.

factors.

Section 109 B(d)(1) of the CAA states:

> Not later than December 31, 1980, and at five-year intervals thereafter, the Administrator shall complete a thorough review of the criteria published under section 108 and the national ambient air quality standards promulgated under this section and shall make such revisions in such criteria and standards and promulgate such new standards as may be appropriate in accordance with section 108 and subsection (b) of this section. The Administrator may review and revise criteria or promulgate new standards earlier or more frequently than required under this paragraph.
>
> (2)(A) The Administrator shall appoint an independent scientific review committee composed of seven members including at least one member of the National Academy of Sciences, one physician, and one person representing State air pollution control agencies.
>
> (B) Not later than January 1, 1980, and at five-year intervals thereafter, the committee referred to in subparagraph (A) shall complete a review of the criteria publisehd under Sec. 108 and the national primary and secondayr ambient air quality standards promulgated under this section and shall recommend to the Administrator any new national ambient air quality standards and revisions of existing criteria and standards as may be appropriate under Section 108 and subsection (b) of this section.

As plainly mandated by Congress the NAAQS is a standard which should be continually updated to reflect changes in scientific data on health effects, and in the case of the secondary standard, control techniques as well as the range of effects from air pollution. Not only the level of these standards, but also the number of these "criteria" pollutants can be changed by the EPA Administrator at any time. Once these NAAQS are set state air laws and state implementation plans must be designed to insure that the standards are met. Penalties paid by areas not meeting these standards are described in the section of this report on the state implementation plans. Engineers have often found if difficult to reconcile the contrasts between twenty year planning and the evolving nature of the NAAQS.

In the past year two changes have occurred to the NAAQS. A new ambient standard for lead was created, at the level of 1.5 $\mu g/m^3$ with a three month average. In addition, the one hour average ozone standard was increased from 160 $\mu g/m^3$ to 235 $\mu g/m^3$. These two changes have not had a significant impact on the utility industry.

Dr. Benjamin Ferris, in an influential review article concerning the NAAQS standards stated [2] :

> The present primary standards for the six regulated pollutants seem adequate to protect the health of the public. Some of the standards do offer a greater degree of protection than some of the others. Until more data are available they should not be changed, up or down. There does seem to be a need to establish a 24 hour standard for NO_2. There are insufficient and inadequate data to establish a standard for sulfates at this time ...

b. Proposed

Despite the fact that Ferris advocates just one new standard, Dr. Amdur of the EPA Scientific Advisory Board reports that five new standards are under study at EPA [3].

- i. Inhalable particulate (less than 15 μm)
- ii. Fine particulate (less than 3 μm)
- iii. Combined particulate and SO_2
- iv. Short term NO_2 standard
- v. Ambient sulfate standard

Each of these potential standards passes through an involved review process which begins with discussion both in the scientific community and the general public. At the instruction of the EPA Administrator, an Air Quality Criteria Document is drawn up. Section 108 of the CAA instructs the Administrator to draw up air quality criteria for air pollutants:

> (A) emissions of which, in his judgment, cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare ...

Draft criteria documents are prepared by the Environmental Criteria and Assessment Office of EPA. Draft documents are reviewed by the Clean Air Scientific Advisory Committee, and comments are invited from the general public. After consideration is given to the comments received, the Administrator of EPA officially issues a final criteria document along with a proposal for a new NAAQS if he feels that one is desired. The proposed standard and the issuance of the document must be announced in the Federal Register, and copies of the criteria document are made available to the general public.

Section 109 (a)(1)(B) of the CAA states:

> (B) after a reasonable time for interested persons to submit written comments thereon (but no later than 90 days after the initial publication of such proposed standards)(the Administrator)

shall by regulation promulgate such proposed national primary and secondary ambient air quality standards with such modifications as he deems appropriate.

i. Inhalable particulate

ii. Fine particulate

An inhalable particulate standard would not require the issuance of a new criteria codument, but would entail a modification of the present criteria document for TSP. The present document reviews health effects primarily with respect to total particulate, an atmospheric measure much easier to obtain than particulate as a function of size.

The 1977 amendments to the CAA require that all criteria documents be reivsed and updated by 1980. The revision of the TSP document has been particularly controversial due to a suit by the American Iron and Steel Institute (AISI) attempting to force the EPA to revise the document before revised state SIPs are due in 1979. The steel industry is concerned that '79 SIPs will force them to take measures to control emissions that will not be considered harmful under the revised qir quality criteria. Specifically the AISI claims that the severity of the present standard is not well supported by scientific data. The industry is claiming that the revised document will exempt certain of their emissions as being large and therefore not dangerous from a health standpoint.

In July, 1978 the EPA issued a strong response to the contentions of the steel industry. In a paper entitled "Issues Related to the Reassessment of the Particulate Matter Ambient Air Quality Standards" the EPA stated [5]:

> Contrary to the position taken by the steel industry, it is EPA's belief that the current standards are reasonable in the light

> of available evidence. The standards have been under essentially constant review over the past several years, and the Agency believes its position is widely supported by the scientific community. Therefore, it is unlikely that an accelerated review in December of this year would produce anything but a reaffirmation of the present standards.

The paper goes on to quote a National Academy of Science publication which affirms the present standard and states:

> There is now a clear need for much more precise specifications of particles and their characteristics, particularly their size distribution.
>
> The scientific community has long advocated a consideration of particle size in the analysis of particulate matter. [6]

Dr. Amdur has measured respiratory resistance in guinea pigs as a function of particle size for two different species of sulfate particles. [7] She reports the following results:

. – Effect of particle size on irritant potency.

Compound	Size μm	No. of Animals	$\mu gSO_4/m^3$	% Incr. Resistance	% Incr. per $\mu gSO_4/m^3$
H_2SO_4	0.1	10	74	32[2]	0.432
"	0.3	23	100	41[2]	0.410
"	0.7	10	120	43[2]	0.358
"	1.0	9	68	14[2]	0.205
"	2.5	10	215	18[2]	0.084
$Zn(NH_4)_2(SO_4)_2$[1]	0.29	12	163	22[2]	0.135
"	0.51	9	981	43[2]	0.044
"	0.74	10	914	21[2]	0.023
"	1.4	6	718	5	0.007

[1] Data of Amdur and Corn, 1963

[2] Significant $p < 0.01$

Table 1.2

The Health Effects Research Lab (HERL) of EPA has surprised many members of that community with their choice of 15 μm as the point at which to distinguish between small and large particles. (Many scientists have suggested that the point where a distinction should be drawn is 1 μm [6,7].) In a document entitled "Health Effects Considerations for Establishing a Standard for Inhalable Particulate"[8] HERL recommends:

> ...a standard for inhalable particulate should include particles of less than 15 μm aerodynamic equivalent diameter. This recommendation is based on the worst case situation, mouth breathers, and represents that fraction of particulate matter which can deposit in the conducting airways, and the gas exchange areas of the human respiratory system; particles greater than 15 μm are restricted to the nasopharyngeal region. The Health Effects Research Laboratory also recommends that a second particle size cutoff of 2.5 μm diameter be incorporated in the selected air sampling device, based upon considerations of the chemical composition and the size distribution of airborne particles, and on the predominant penetration of particles less than 2.5 μm diameter to the gas exchanges region of the respiratory tract. Data collected in this size range could be used in conjunction with epidemiological health parameters to refine an inhalable particulate standard in the future.

The document reveals that a fine particle standard (less than 2.5 μm) will not be set in the near future due to the difficulties of distinguishing fine particles with present techniques and the associated problems of documenting health effects from fine particles. The author has noted that particle size data measured by different techniques will often vary considerably. A disturbing aspect of the problem revealed in the HERL document is that fine particulate matter in the atmosphere is generally 60 - 80% secondary, that is, particulate matter formed in the atmosphere rather than originating from point sources such smoke stacks. The annual average composition of fine particulate in the Eastern U.S. for '66 - '68 was dominated by the following constituents:

sulfates	18.9 $\mu g/m^3$
organics	7.8 $\mu g/m^3$
nitrates	2.1 $\mu g/m^3$
lead	1.2 $\mu g/m^3$

The HERL document also reports that the fine mass fraction of the total suspended particulate matter varies from 15 - 25% in Denver to 40 - 60% in the Los Angeles and New York-New Jersey urban areas.

A recent article reports that EPA is setting up a network to monitor amount, chemical, and biological properties of particulate less than 15 μm and less than 2.5 μm. [9] The Environmental Monitoring and Support Laboratory is presently investigating different techniques for gathering the data, and eventually hopes to put 300 units in the field. Particular attention will be paid to the carcinogenic nature of particulate matter, as a recent article in Science reports that fine particles of fly ash are shown to a powerful carcinogens according to the Ames test. [10]

The direction which the particulate matter standard will take in 1980 is best illustrated by comments from the cited EPA issue paper [5] and a memorandum from David Hawkins, assistant administrator of EPA, to EPA regional administrators. [11] The issue paper states that although control of particles greater than 15 μm may be deferred after 1980 with respect to the health-based primary standard, it is unlikely that there will be any change in the welfare-based secondary standard. The paper states that the exact measure of the inhalable particulate standard will not be determined until more tests are conducted during the next two years, but the language of the discussion seems to imply that the resulting primary standard will be less severe than our present standard, due to the deletion of the larger particles from the total mass count. The issue paper states in summary that the steel industry will be only marginally affected by changes in the standards, its emissions being primarily under 15 μm in size. Hawkins acknowledged in his letter, "some controls that would be necessary to attain the current NAAQS may not be necessary to attain a revised primary NAAQS." He specifically mentioned sources "as storage piles and material handling operations that emit relatively large particles," Hawkins outlined a procedure by which states could modify their SIPs to insure that industry is not forced to adopt measured that will prove to be unnecessary under the revised standard.

This author anticipates that changes in the NAAQS for particulate matter in 1980 will have a negligible effect on utility operation. It is possible that currently planned restrictions on coal and ash handling techniques could be eased. As more data becomes available from the EMSL program of gathering atmospheric data with dichotomous samplers, correlations with clinical and epidemiological studies will build support for fine and inhalable particulate standards in the 1980s. Dr. Pate of EPA's office of Strategies and Air Standards, currently working on a combined criteria document for particulates and sulfur oxides, in a phone conversation suggested that by the mid-1980's there will quite likely be a fine particulate standard [12]. She suggests that by the mid-1980's documentation will grow to confirm what scientists have suggested for some time, that fine particulates have greater health effects. Of coruse, lacking this future data, it is impossible to speculate on the severity of the standard.

iii. Combined particulate and SO_2

Consistent with the requirements of the Clean Air Act amendments of 1977, the criteria documents for particulate matter and sulfur oxides will be revised by 1980. EPQ has decided to combine the two documents into one upon revision because: [13]

1. SO_2 by itself in concentration normally found in the ambient air does not appear to be the cause of adverse human health effects;
2. Virtually all of the recent human health data indicates that detrimental effects occur when sulfur oxides and particulates are interacting;
3. Acidic precipitation (wet deposition), a growing cause for concern due to the damage it is causing to aquatic and terrestrial ecosystems as well as to materials, results when sulfur oxides and particulates are in association.

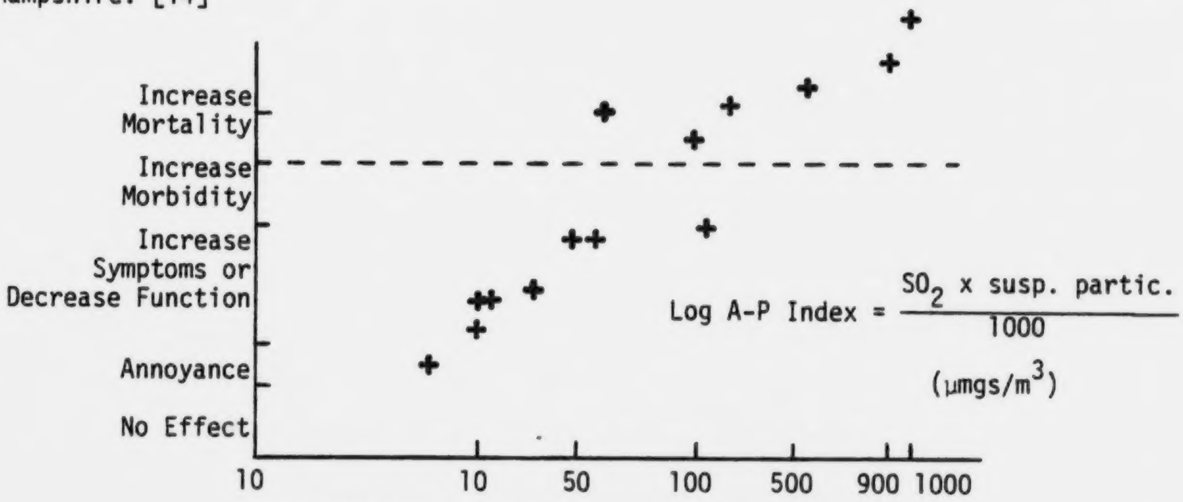
These reasons are quoted from the project plan for the drafting of the combined document. The project plan, as well as the full criteria document, will be drafted by the Environmental Criteria and Assessment Office of EPA. The project plan states:

> The increased health effects of SO_2 and particulates in combination, when compared to their independent action, is due to the transformation of SO_2 into a variety of products including sulfuric acid and

sulfate salts. Both of these sulfate compounds are more highly irritating than SO_2 alone. Sulfate appears to be contained in association with particles of small size, 2 μm or less.

Some confusion seems to presently exist at EPA concerning whether support data for an inhalable particulate standard will appear in the 1980 combined particulate and sulfur oxides document. Dr. Pate speculated that the support data for any inhalable particulate standard will be issued too late for inclusion in the new document, and will have to appear in a separate support document. [12]

Combination of the two criteria documents does not necessarily imply that a standard will be drafted which combines these two materials. Dr. Ferris of Harvard prepared a dose-reponse curve based on the product of the two concentrations from a study he conducted on school children in Berlin, New Hampshire. [14]



DOSE-RESPONSE OF THE SO_2 -- PARTICULATE PRODUCT

Other scientists have proposed that there is a synergistic relationship between the two materials. [15] But despite the fact that particulate sulfate derives from SO_2, high particulate and sulfur oxide levels are not always found simul-
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taneously. The recently issued eighth annual "Environmental Quality" states, "Simultaneous violations of total suspended particulate and sulfur dioxide standards are rare, occurring only in a few lightly populated areas." [16]

Commenting on the present SO_2 standard, the National Academy of Science recently stated "there is no justification for changing the current ambient air quality annual average for sulfur dioxide, though more studies should be done on the subject...the present 24 hour so_2 standard is reasonable in light of current evidence." [17] It would appear that a new standard would only be required if the present allowable SO_2 levels were dangerous when accompanied with a high background level of particulate. This is a situation which, according to Environmental Quality, does not frequently occur.

iv. Short term NO_2 standard

A great deal of pressure has recently been brought to bear on the EPA to adopt an NO_2 standard averaged over a shorter time scale than the present annual mean standard. A significant push is contained in the '77 amendments to the Clean Air Act. Section 109(c) states:

> The Administrator shall, not later than one year after the data of the enactment of the Clean Air Act Amendments of 1977, promulgate a national primary ambient air quality standard for NO_2 concentrations over a period of not more than three hours unless, based on the criteria issued under section 108(c), he finds that there is no significant evidence that such a standard for such a period is requisite to protect public health.

In addition, the review of Ferris has already been cited which advocates a short-term standard for NO_2. [2]

Standards for NO_2 can have a significant impact on utility operations. The DOE reports that 24% of all NOX emissions in 1975 for Region I (northeast U.S.) were from utility plants. [18] Industrial fuel users accounted for another 7% of the total. Utility emission of NOX is presently controlled through lowering boiler temperatures and cutting back on excess air. A by-product of these measured can be an increase in the amount of carbon in the resulting boiler ash. This unburned carbon can have an effect on the operation of particulate control systems, and therefore is an important consideration for this study.

Several different viewpoints concerning a new NO_2 standard were presented in the June, 1978 APCA Journal. [19] APCA reports that the EPA has suggested it might propose a one-hour ambient standard of between 0.25 and 0.5 ppm. Most industry groups contend that there is no need for the standard at all. Environmentalists have advocated that EPA adopt the World Health Organization's recommended standard of 0.1 to 0.17 ppm, averaged over one hour. Ferris has suggested that an appropriate standard would be 0.26 ppm averaged over one hour, not to be exceeded more than two or three times per year. Ferris's one-hour standard is at a level 4.8 times greater than the present annually averaged NO_2 standard.

In response to pressures from Congress and the community EPA drafted a document "Health Effects of Short-Term Exposures to Nitrogen Dioxide" in January of 1978, and has completed a new draft criteria document for oxides of nitrogen, which has been completed since November, 1978. [20] This draft document is under review by the Science Advisory Board and public comments are invited up to February 28, 1979. Upon incorporation of comments to the document, a decision will be made as to whether to propose a new NAAQS standard, and this new standard will be announced along with the release of the final cirteria document. The EPA office of Air, Noise, and Radiation will be responsible for proposing a standard, with the Administrator responsible for making the final decisions. [20]

v. Ambient sulfate standard

There has been significant public debate over the last several years concerning the merits of adopting an ambient sulfate standard. Pressure on EPA has come not only from the scientific community, but also from the EPA Scientific Advisory Board. In response to this pressure EPA issued "Position Paper on Regulation of Atmospheric Sulfates" in September, 1975 [21]. In this paper the EPA acknowledged that an ambient sulfate standard might be advisable, but stated:

> Considering the uncertainties in scientific information, it will take three to five years of additional research before a major sulfate regulatory program is possible. Until then, present concerns dictate that EPA follow a policy of avoiding increases in SO_2 emissions and consequenct sulfate increases in the 24 state region and other areas subject to high sulfate levels.

The 24 state region referred to in this statement includes the northeastern United States. The scientific information referred to in this statement which is lacking includes techniques for adequately measuring sulfate, an understanding of how sulfates are formed in the atmosphere and which materials are serving to catalyze the conversion of SO_2 to sulfate. Finally, there is still uncertianty concerning the health effects of sulfates.

Ferris, in his previously quoted review article [2] stated, "At present there are no adequate data to set a standard for sulfates or even sulfuric acid mist in the atmosphere." The National Academy of Science stated in December, 1978, that data is currently insufficient to set an ambient standard for sulfates. [17]

In a recent article entitled "Potential Ambient Standards for Atmospheric Sulfates: An Account of a Workshop" [22], a potential ambient sulfate standard was drafted. It was considered that the following standard could become feasible between 1978 and 1985:

Total water soluble sulfates

10-25 $\mu g/m^3$	24-hour average
5-15 $\mu g/m^3$	annual average

This standard, if adopted, could have an effect on utility operations in the Northeast. The 1978 report "Environmental Quality" states that many areas in Connecticut have annual sulfate levels of from 10 - 15 $\mu g/m^3$, and other areas in New York and Pennsylvania have levels as high as 15 - 20 $\mu g/m^3$. [23] In reference to a potential sulfate standard the 1978 "Environmental Quality" states" "Issuance of a primary standard for sulfates does not appear likely in the immediate future. Clinical studies show health effects from sulfuric acid and other sulfates, but at higher levels than are typically observed in the ambient air." [24]

An ambient sulfate standard could become a reality if further studies, such as the one already cited by Dr. Amdur, [7] pervasively prove the need for such a standard. A sulfate standard would strongly impinge on utility operations because:

1. Two-thirds of all sulfur emissions are from coal and oil-fired powerplants. [25]

2. Agents assisting the conversion of SO_2 into sulfates are apparently emitted from powerplant stacks.

An article from EPRI states, "The primary mechanism for the formation of sulfuric acid and sulfate in the Midwest and Northeast, where high ambient sulfate concentrations exist, appears to be the catalytic conversion of atmospheric SO_2 and water in the presence of metallic catalysts such as vanadium, iron, etc., in fine particulate form." [26] The cited EPA review article on potential sulfate standards [21] observed: "Limited experimental results indicate that within some types of plumes from oil-fired power plants, sulfur dioxide can be rapidly converted to sulfates."

2. Massachusetts and Connecticut State Air Laws and State Implementation Plans

In both Massachusetts and Connecticut environemntal regulations are drafted by designated departments under the authority of the state legislatures. In Massachusetts Section 142, Chapter 111 of the general laws authorizes the Department of Environmental Quality Engineering (DEQE) to, "adopt or amend regulations to prevent pollution or contamination of the atmosphere." [28] Chapter 360 of the General Statutes of Connecticut delegates similar authority to the Connecticut Department of Environmental Protection (DEP). Massachusetts Air Pollution Control Regulations numbering from 7.00 to 7.60 were most recently updated and published on May 4, 1978 by the DEQE [29]. Regulations entitled "Abatement of Air Pollution" were published on February, 1978 by the DEP and number from 19-508-1 to 19-508-100. [30]

State environmental agencies are responsible for submitting regulations, state laws, and other documents to the regional EPA which constitute the state implementation plan (SIP). The EPA can reject part or all of the plan and revise it to become consistent with federal requirements. The final SIP consists essentially of the state regulations and revisions instituted by the EPA which are listed in the Federal Register. Upon approval the state environmental agencies are responsible or enforcing the plan, with the federal enforcers authorized to step in under guidelines listed in Section 113 of the CAA.

Regulations 7.02, 7.04, 7.05, and 7.06 of the Massachusetts DEQE affect fossil fuel utilization facilities. According to regulation 7.02 fossil fuel utilization facilities must achieve the emission standard shown in Tables 1.3 and 1.4.

Regulation 7.05 stipulates the sulfur content of fuel permitted for use in the various AQCR. In the case of flue gas desulfurization, proportionately higher sulfur contents are permitted by permission of the DEQE. This regulation is constantly under revision according the the dictate of Chapter 494, approved July 9, 1974, which amends the Massachusetts Air Pollution Laws. The amendment is contained in the second chapter of Section 142D, Chapter 111 which currently reads:

> From time to time the department shall review the ambient air quality standards and plan for implementation, maintenance, and attainment of such standards adopted pursuant to this section and, after public hearings, shall amend such standards and implementation plan so as to minimize the economic cost of such standards and plan for implementation, provided, however, that such standards shall not be less than the minimum federal standards. The initial such amendments to such standards and implementation plan shall

TABLE 1.3

EMISSIONS LIMITATIONS

Fossil Fuel Utilization Facilities

PARTICULATES

Facility Size Million Btu/hr. Input	Emission Limitation lbs. (particulate)/million Btu		
	new	existing	existing (critical area of concern)
3 - 250	0.10	0.15	0.12
greater than 250	0.05*	0.15	0.12

The following cities and towns are defined as critical areas of concern: Berkshire Air Pollution Control District -- Adams, Dalton, Lee, North Adams, Pittsfield.

Central Massachusetts Air Pollution Control District -- Athol, Auburn, Boylston, Litchburg, Gardner, Grafton, Holden, Leicester, Leominster, Millbury, Shrewsbury, Southbridge, Webster, West Boylston, and Worcester.

Merrimack Valley Air Pollution Control District -- Haverhill, Lawrence, Lowell and Newburyport.

Metropolitan Boston Air Pollution Control District -- Arlington, Belmont, Boston, Braintree, Brookline, Cambridge, Canton, Chelsea, Dedham, Everett, Lynn, Malden, Medford, Melrose, Milton, Needham, Newton, Peabody, Quincy, Revere, Salem, Saugus, Somerville, Stoneham, Wakefield, Waltham, Watertowm, Weymouth, Winchester, Winthrop and Woburn.

Pioneer Valley Air Pollution Control District -- Amherst, Chicopee, East Hampton, East Longmeadow, Greenfield, Hadley, Holyoke, Longmeadow, Ludlow, Northampton, Orange, Palmer, Springfield, Ware, Westfield, and West Springfield.

Southeastern Massachusetts Air Pollution Control District -- Attleboro, Fall River, New Bedford, Sandwich, Somerset, and Taunton.

* An emission rate of 0.10 lbs (particulate) per million Btu will be allowed if a person is using equipment designed to control or reduce sulfur dioxide at the same time or in the same process so that the provisions of 7.05 are satisfied.

TABLE 1.4

OXIDES OF NITROGEN

New Facility Size Million Btu/hr. input	Emission Limitation-pounds/million Btu		
	Type Fuel		
	Gaseous	Liquid	Solid
Greater than 250	0.20	0.30	0.70

TABLE 1.5

VIOLATIONS OF THE TSP NAAQS IN MASSACHUSETTS DURING 1977[*]

SITE	Annual Geom. Mean	# of Observ.	24 hour Primary	24 hour Secondary
Worcester Narcus Department Store	54	254	1	10
Worcester Washington & New Salem Sts.	89	248	25	44
Worcester Health Department	51	49	1	3
Boston Kenmore Square	79	43	2	7
Waltham Main & Moody Sts.	69	42	0	3
Springfield East Columbus Ave.	121	45	5	11

[*] Units are in $\mu g/m^3$. The annual primary standard is 75 $\mu g/m^3$, the 24 hour primary standard is 260 $\mu g/m^3$, and the 24 hour secondary standard is 150$\mu g/m^3$. A violation of the 24 hour standards occurs if the level exists more than once per year.

> postpone the achievement dates for the primary and secondary ambient air quality standards to the latest dates permitted pursuant to federal law.

The DEQE report, "Executive Summary 1976 and 1977 Annual Air Quality Report" [31] reports no recorded violations of SO_2 or NO_2 NAAQS in Massachusetts for 1976 and 1977, but reports 11 of 55 sampling sites in violation of the TSP standard for 1976 and 6 of 56 sampling sites in violation for 1977. Consequently, the primary impact of Chapter 494 on utility fossil units has been to increase the allowed sulfur content of fuel.

With respect to TSP violations the Exectuive Summary states, "There has been some question concerning the representativeness of these TSP violations. The Division feels that the violations are primarily due to the influence of passing traffic kicking up road particles, dust, etc., in the vicinity of the TSP monitors. If this theory is correct, the recorded violations would not be truly representative of ambient air quality in these areas. A number of industries and utilities in Massachusetts and the US D.O.E., along with the Division of Air and Hazardous Materials (the division of the Massachusetts DEQE which deals with air quality) and the Massachusetts Technology Development Corporation have combined resources in a large study to determine the exact cause of these TSP violations." The six TSP violations for 1977 occurred at the sampling sites indicated in Table 1.5.

Mr. Irving Sacks of the Massachusetts Technology Development Corporation was interviewed to gather information on the potential effect of his study on attainment of the TSP standard in Massachusetts [32]. He reports that tests were conducted in Fall River, Kenmore Square, and Springfield. Dichotomous samplers were utilized which gave information on particles less than 3 μm in diameter and between 3 μm and 20 μm. Results have shown that fine particulate levels are generally independent of distance from road, time of day, and other factors, while the larger particle fraction would vary almost proportional to nearby traffic levels and vary significantly with the distance from the road. On a rainy day the large particle fraction could constitute half of the total, while on a dry day it could constitute two-thirds. Tests on the chemical nature of the various components are currently in progress. Mr. Sacks speculates that the study could be used to support moving monitors away from roadways. Based on the results cited, it would seem likely that moving monitors away from roads would bring the state into compliance.

Table 1.6 shows the current regulations for sulfur in fuel content for the various AQCR. Special permission for the use of the higher sulfur fuels listed is granted by the DEQE with the approval of the EPA. The decision is based on worst case meteorological modeling to determine if the higher sulfur fuel will cause violations of the NAAQS. The regulations stipulate that a source burning the higher sulfur fuel must be ready to fulfill the following requirement: "The facility has available, ready for conversion within six (6) hours of notice from the Department a three (3) day supply of fuel with a lower sulfur content as specified by the Department which shall be utilized during periods of adverse meteorological conditions when directed by the department..."

Federal EPA approval of SIP revisions are published in the Federal Register. The approval extending Southeastern Massachusetts APCD 1.21 lb/MMBtu sulfur in fuel program to July 1, 1979 specifically disallows four of the seventeen potential users in that area from burning the higher sulfur fuel. [33] According to EPA modeling these sources could cause violations of the NAAQS for SO_2. In addition, EPA stated, "Since violations of the NAAQS for total suspended

TABLE 1.6 Sulfur in fuel regulations for plants with an energy input of 10^8 Btu/hr or greater

AQCR DISTRICT	FUEL PERMITTED ($\frac{\text{lb}}{\text{MMBtu}}$) (approx. equiv. oil)		For cases where special permission is received and under the following conditions	FUEL PERMITTED ($\frac{\text{lb}}{\text{MMBtu}}$) (approx. equiv. oil)	
Berkshire APCD	1.21	2.2% S			
Central Area APCD	.55	1% S	Towns other than Fitchburg and Worcester	1.21	2.2% S
Merrimack Valley APCD	.55	1% S	Fitchburg between 4/1 and 11/1. Towns other than Lawrence, Andover, Methuen, and North Andover	1.21	2.2% S
Metropolitan Boston APCD Arlington, Belmont, Boston Brookline, Cambridge, Chelsea, Everett, Malden, Medford, Newton, Somerville, Waltham and Watertown	.28	.5% S	Electric generating facility greater than $2.5 \times 10^9 \frac{\text{Btu}}{\text{hr}}$	.55	1% S
Other Towns	.55	1% S	--	1.21	2.2% S
Pioneer Valley APCD	.55	1% S	--	1.21	2.2% S
Southeastern Massachusetts APCD	.55	1% S	--	1.21	2.2% S

particulates (TSP) have occurred throughout Massachusetts, and since use of higher sulfur fuel may result in increased particulate emissions, all sources converting to higher sulfur fuel were required by the Massachusetts Department to conduct emission tests for particulate matter."

Regulation 7.06 limits the permitted opacity for Massachusetts sources, exclusive of water vapor, to 20%. In addition, these Massachusetts regulations contain numerous testing, reporting, and operating procedures which must be respected by the area utilities.

A regulation which has been proposed by the DEQE and approved by the EPA is, "7.17 SE Coal Conversion - Brayton Point Station, New England Power Co." [34] This regulation would extend the expiration of the period during which Brayton Point can burn 1.21 lb/MMBtu fuel to November 1, 1988 rather than the July 1978 date on which other regulations allowing higher sulfur content fuel expire. In addition, the regulation permits Brayton Point to average the sulfur content of its fuel on a monthly basis as long as emissions do not exceed 2.31 lb/MMBtu on any particular day. A compensating point of the regulation limits the facilities particulate emission to 0.08 lb/MMBtu, below the 0.12 lb/MMBTU which would normally be permitted for this facility.

Connecticut regulation 19-508-18 stipulates that opacities may not exceed 20% except for up to five minutes each hour during which time the opacity may not exceed 40%. Particulate emissions are limited to 0.2 lb/MMBtu for sources existing before June 1, 1972, and are limited to 0.1 lb/MMBtu for new sources. Fuel burning sources with particulate emission systems in place are required to maintain the equipment in proper condition. Regulation 19-508-19 limits the sulfur content of fuel to 0.5% after April, 1973. Special permission can be received from the Commissioner (of the DEP) to burn higher sulfur fuels if stack-gas cleaning is utilized and the resulting sulfur emissions are less than 0.55 lb/MMBtu. The document, Connecticut Air Quality Summary--1977" [35] shows that Connecticut recorded no violations of the SO_2 NAAQS in 1977. The following table showing the attainment status of the Connecticut AQCRs is taken from the Air Quality Summary with some modifications provided by a phone conversation with DEP personnel:

TABLE 1.7

COMPLIANCE WITH TSP NAAQS FOR 1977 BY AQCR

		AQCR 41	AQCR 42	AQCR 43	AQCR 44
Primary	Annual	A	N	A	A
	24-Hour	A	N	A	A
Secondary	Annual	N	N	N	N
	24-Hour	N	N	N	N

N = Non-Attainment
A = Attainment

Mike Anderson, Senior Air Pollution Control Engineer with the Connecticut DEP was contacted to clarify discrepancies between Massachusetts and Connecticut reporting. [35] He reports that the table above was sent to EPA in Janaury, 1979 as part of the draft revised Connecticut SIP. There is a possibility that AQCR 42 will be declared attainment for the primary standard except in Waterbury, the location where the violations were recorded. Mr. Anderson reports that Connecticut takes a sample from each of its 45 TSP monitoring sites at least once each six days as stipulated by EPA procedures. If 46 of these samples yield valid numbers then a statistically significant sample has been obtained. The DEP then projects the available data out to 365 days by assuming that ambient levels are log-normally distributed. If this technique indicates that violations would have occurred on more than one of the 365 days, a violation of the standard is declared. Massachusetts declares a violation of the standard to have occurred if two days were actually measured in violation.

Sampling site Waterbury-123 illustrates the effect of this difference in reporting. Samples were taken on 118 days in 1977. The annual geometric means for these samples was 81.3 $\mu g/m^3$, so a violation of the annual standard is apparent. The highest recorded 24-hour sample was 292 $\mu g/m^3$, while the second highest was 255 $\mu g/M^3$. Connecticut projects that on the basis of 365 samples 4 violations of the 260 $\mu g/m^3$ primary standard would have occurred. Therefore they have declared AQCR 42 non-attainment for the 24-hour primary standard. Massachusetts would have declared the area in attainment, as two days in violation were not recorded. Mr. Anderson reports that the EPA declares an area non-attainemnt if two violations are measured, but instructs the states to take more samples if the status of an area is in question.

Unlike the primary standard, two violations of the TSP 24-hour secondary standard were actually measured in each AQCR. The TSP annual secondary standard is not recognized in many states, and is only used as a guide by the EPA. Mr. Anderson reports that in his judgment as much as 60% of the filtered samples from many of his monitors can be attributed to automobiles. He specifically cites the stirring up of road dust, tire, and brake wear as contributing to this problem. He advocates solving the automobile generation problem rather than moving monitors from roads because of the fact that people are breathing this material.

All states are required to have submitted revisions to their implementation plans by January 1, 1979 which incorporate the constraints of the 1977 CAA amendments. [37] On the basis of 1977 monitoring data either entire AQCR or subsections of these regions must be declared attainment or nonattainment of the NAAQS. The status of attainment is determined on a pollutant by pollutant basis. Connecticut has met the January 1, 1979 deadline while Massachusetts has received a three month delay. [38]

Section 172(a)(1) of the CAA states:

> The provision of an applicable implementation plan for a State relating to attainment and maintenance of national ambient air quality standards in any non-attainment area which are required by section 110(a)(2)(I) as precondition for the construction or modification of any major stationary source in any such area on or after July 1, 1979, shall provide for attainment of each such national ambient air quality standard in each such area as expeditiously as practicable, but, in the case of national primary ambient air quality standards, not later than December 31, 1982.

In the case of violations of the primary standards for photochemical oxidants and carbon monoxide, a revised state plan can be submitted to achieve the primary standard by 1987.

Section 172(b)(3) of the CAA states that the plan revisions required in the preceding paragraph must:

> require, in the interim, reasonable further progress (as defined in section 171(1)) including such reduction in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology;...

Reasonable further progress is defined in Sec. 171(1):

> The term "reasonable further progress" means annual incremental reductions in emissions of the applicable air pollutant (including substantial reductions in the early years following approval or promulgation of plan provisions under this part and section 110(a)(2)(I) and regular reductions thereafter) which are sufficient in the judgment of the Administrator, to provide for attainment of the applicable national ambient air quality standard by the date required in section 173(a).

The term major source is defined in the definition section as any source with a potential emission rate of 100 tons/year for any air pollutant. Section 110(a)(2)(H)(ii) stipulates that the implementation plan must incorporate the following provision:

> it provides for revision, after public hearing, of such plan... whenever the Administrator (EPA) finds on the basis of information available to him that the plan is substantially inadequate to achieve the national ambient air quality primary or secondary standard which it implements or to otherwise comply with any additional requirements established under the Clean Air Amendments of 1977;...

Section 112 of the CAA has already been cited which permits the Administrator to enforce a state implementation plan if the state is not properly performing this duty.

The result of these regulations is to put pressure on the states to achieve at least the primary NAAQS by 1982 (except for the automobile-related pollutants). In addition to the threat of direct enforcement cited above, the CAA provides strong economic incentives for states to revise their plan and meet the NAAQS. The most important of these incentives is the threat to economic growth posed by a cutoff of permits to new or modified major sources (the definition of modification is given in Sec. 3 which concerns new source performance standards).

States must incorporate one or two programs into their SIPs to permit new or modified major sources in nonattainment areas. States can devise standards for existing sources and bring these sources into compliance at such a rate that they can be in compliance by 1982 and "provide a quantified margin for emission growth for new construction,,," An alternate plan allows the state to devise an offset plan, whereby existing sources must reduce their emissions beyond that required for attainment in order that total emissions resulting from the permitting of a new major source will be less than zero. New major sources are required to comply with "lowest achievable emission rates", and will only be allowed if the applicable implementation plan is being carried out. Lowest achievable emission rate is defined in Sec. 171(3) of the CAA:

> (3) The term "lowest achievable emission rate" means for any source, that rate of emissions which reflects--
>
> (A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

> In no event shall the application of this term permit a proposed new or modified source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance.

In the event of a revision to a NAAQS, states are given nine months to incorporate the revision into their implementation plans. The plan revisions should be approved by the EPA within 120 days, and the states are given three years to implement the plan revisions and attain the new standard. Under CAA Section 110(e) this period may under special circumstances be extended for an additional two years.

Under the '77 amendments to the CAA permitting of new major sources in attainment areas is also restricted. Areas in attainment for a particular pollutant are declared "Prevention of Significant Deterioration" or PSD. Regions defined PSD are classified either class I, II, or III, with certain Federal areas automatically classified as class I, and all other areas initially classified as class II. Prevention of significant deterioration requirements for state implementation plans are discussed in a subsequent section dealing exclusively with that subject.

There are many avenues by which utility operations could be impacted by changes in state air laws. It seems likely that Massachusetts will be able to effectively lift the status of nonattainment of the primary TSP NAAQS from the state. Nonattainment of the secondary TSP standard will probably continue for some time barring significant changes in measuring techniques, e.g., with respect to emissions caused by motor vehicles. Nonattainment of the secondary standard beyond the time provided for by the CAA could force state control agencies to tighten up on permits. States with nonattainment areas are compelled under the act to adopt standards which force existing sources to utilize "reasonably available control technology".

Existing sources will also be compelled to meet new standards in the event of a change in the NAAQS. According to the statutory timetable provided in the CAA states should be in compliance with a new NAAQS standard within four years of the proposal of such a standard.

Finally, existing sources can be impacted by a desire on the part of a state to permit a new major stationary source to obtain an emission offset. The requirements which will bear on the new source are discussed in the section on new source performance standards. In states not in attainment with standards new sources can squeeze emissions out of existing sources in order to provide an offset to allow a new source. States in attainment, or PSD areas, must keep ambient levels below set increments and can achieve these increments in the face of growth by squeezing existing permits.

3. New Source Performance Standards

Section 111 of the CAA entitled, "Standards of Performance for New Stationary Sources" brings the federal government squarely into the business of setting emission standards for new or extensively modified sources. For fossil fuel fired stationary sources the standard is defined in part a:

> For the purpose of subparagraphs (A)(i) and (B), a standard of performance shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the

> Administrator determines has been adequately demonstrated. For the purpose of subparagraph (1)(A)(ii), any cleaning of the fuel after extraction and prior to combustion may be credited, as determined under regulations promulgated by the Administrator, to a source which burns such fuel.

Part (a)(1)(A) specified that for fossil fired units the standard must be:

(i) establishing allowable emission limitations for such category of sources, and

(ii) requiring the achievement of a percentage reduction in the emissions from such category of sources from the emissions which would have resulted from the use of fuels which are not subject to treatment prior to combustion.

Although the NSPS emission limitations are set by federal regulations, part (c) of Sec. 111 allows the Administrator (of EPA) to grant enforcement authority to the various states if their programs are deemed adequate. When a state is authorized to enforce its own NSPS program, the Administrator does not reliquish his enforcement authority. Authority was granted to MA to enforce its own NSPS program in 1976 [39].

New source standards for steam generators were originally established on December 23, 1971. This standard, applicable to all sources which commenced construction after December 23, 1971 specifies the emission limitations listed in Table 1.8 [40].

The EPA was petitioned on August 6, 1976 by the Sierra Club and the Oljato and Red Mesa chapters of the Navaho trive to revise the SO_2 standard so as to require a 90% reduction in SO_2 emissions from all coal-fired power plants. [41] This petition was supported by documents which claimed that

Table 1.8

Emission Limitation for 1971 NSPS in lb/MMBtu

Pollutant	Solid Fuel	Liquid Fuel
SO_2	1.2	0.80
Particulate Matter	0.10	0.10
NO_x	0.70	0.30
Opacity	20%	20%

significant advances in SO_2 control technology had been achieved since the drafting of the '71 standard. Subsequently, the 1977 CAA amendments required standard revisions incorporating percentage reductions. The act states, "The revised standards of performance required by enactment of subsection (a)(1)(A) (i) and (ii) shall be promulgated not later than one year after enactment of this paragraph."

Although the EPA did not meet the August 7, 1978 deadline specified in the CAA for promulgation of the revised standard, after court action initiated by the Sierra Club an agreement was reached to deliver the proposal package to the office of the Federal Register by September 12, 1978, and to promulgate the final standards within 6 months after proposal. The proposed standard appeared as a 30 page package in the September 19 issue of the Federal Register [12].

The EPA proposal was referred to as a "full scrubbing" proposal because an 85% daily averaged SO_2 reduction was required regardless of the level of the uncontrolled emissions. A maximum SO_2 emission level of 1.2 lb/MMBtu for solid fuels would have been allowed, and the percentage reduction rule would not apply for emission levels below 0.2 lb/MMBtu.

Most solid fuels would fall between the upper and lower SO_2 emission limits, since for nominal 10,000 Btu/lb fuel they correspond to fuels with greater than 4%S content and fuels with lower that 0.67%S content respectively. For liquid fuels an upper emission limit of 0.8 lb/MMBtu would have applied. The EPA considered a daily averaged reduction level ot 85% equivalent to a monthly averaged level of 90%. The EPA proposed standard would have allowed for exemptions during plant startup and shutdown, for demonstrations of new technology, and three days per month during which a standard of 75% would be controlling.

Opposition to the EPS proposed SO_2 reduction levels came from many groups and a significant volume of comments were filed and reviewed. The Department of Energy and the Utility Air Regulatory Group proposed partial scrubbing schemes. Environmental groups such as the Sierra Club and the NRDC argued for stiffer standards, particularly for a 90% daily averaged SO_2 reduction level and an emissions ceiling below 1.2 lb/MMBtu.

A significant issue for the determination of the SO_2 control level required is the regional balance of costs and benefits. Congress instructed the EPA to require a percentage reduction for all emissions in order to encourage the use of regional coal reserves, particularly in the midwest. Concern was also voiced over the potential deterioration of air quality in the rapidly expanding southwest region. The background information supplied with the proposed NSPS standard states [41]:

> The utility industry is expected to have continued and significant growth; approximately 300 new fossil-fuel-fired power plant boilers are to begin operation within the next 10 years. Associated with utility growth is the continued long-term increase in utility coal consumption from some 650 million tons/

year in 1975 to between 1,400 and 1,800 million tons/year in 1990. Under the current performance standards for power plants, national SO_2 emissions are projected to increase approximately 15 to 16 percent between 1975 and 1990.

Impacts will be more dramatic in a regional basis. For example, in the absence of more stringent controls, utility SO_2 emissions are expected to increase tenfold to over 2 million tons by 1990 in the West South Central region of the country (Texas, Oklahoma, Arkansas, and Louisiana).

Studies were conducted to determine the difference in impact of adopting either the more stringent EPA or the more lenient DOE proposals. Data released in December was reported in a leading journal [43], "Those statistics--the most recent computer modeling projections on alternative new source performance standards--indicated there may be less difference than previously thought in the rival SO_2 removal plans proposed by EPA and the DOE ....For example, the new projections indicated that a plan corresponding to EPA's official NSPS proposal would produce 19.9 million tons under a partial scrubbing plan roughly similar to one proposed by DOE Deputy Secretary John O'Leary. The full scrubbing plan by 1990 would require 2.2 million barrels of oil per day, compared to 2.0 million under the partial scrubbing plan, and would add 80¢ to monthly utility bills (above that added by the current NSPS) compared to 64¢ under partial scrubbing. Full scrubbing would also cost $1,236 per ton of SO_2 removed beyond that controlled by the present NSPS, compared to $1,090 under the partial scrubbing option. EPA is expected to issue a final ruling in March."

Technical background, economic analysis, and a summary of particulate emission results is contained in the EPA support document for the proposed particulate matter standard [44]. EPA has based its proposed standard of .03 lb/MMBtu on the capabilities of a "well designed and operated baghouse or electrostatic precipitator." The data reported in the support document is summarized with the NSPS proposal in the Federal Register [45]:

> EPA has evaluated data from more than 50 emission test runs conducted at eight baghouse-equipped, coal fired steam generating units. The data from two tests exceeded the proposed standard, however, it is EPA's judgement that the emission levels at the two units which had measured emission levels above the proposed standards could be reduced to below the proposed standard through an improved maintenance program. EPA believes that baghouses with an air-to-cloth ratio of 0.6 actual cubic meters per minute per square meter would achieve the proposed standards at pressure drops of less that 5" W.G. EPA has considered that this air/cloth ratio and pressure drop are reasonable when considering cost, energy, and nonair quality impacts.
>
> EPA collected emission data from 21 ESP-equipped, coal-fired steam generating units. The nominal sulfur content of the coals being fired ranged from 0.4 to 1.9 percent. None of the 21 units tested were designed to achieve an emission level equal to or below the proposed standard of .03 lb/MMBtu heat input; however, emissions from 9 of the 21 units were below the proposed standard. ... EPA evaluated emission levels from units burning relatively low-sulfur coal because it is more difficult for an ESP to collect

particulate matter emissions generated by the combustion of low-sulfur coal than high-sulfur coal...To meet the proposed standard, EPA believes that an ESP used on low-sulfur coal would have to have a specific collection area from around 130 (hot side) to 200 (cold side) square meters per actual cubic meter per second while an ESP used on high sulfur coal (3.5% sulfur) would only require around 72 square meters per actual cubic meter per second . . . EPA believes that a baghouse control system could be applied on utility-size facilities firing low-sulfur coal at a lower cost than an ESP . . .EPA believes that wet particulate matter scrubbers would not be capable of complying with the proposed standards under most conditions.

EPA considered proposing the standard at a level of .05 lb/MMBtu in order to allow the application of wet particulate matter scrubbers in addition to baghouses and ESP's. This option was rejected, because EPA believes that allowing scrubbers would cause an increase in the emissions of fine particulate matter without compensating advantages. In addition to 60% higher emissions, a particulate matter scrubber would require three times as much energy to operate as a dry control system, and would also increase water consumption . . . The primary suggested advantage to allowing the use of scrubbers for particulate matter control would be to allow a single scrubber to control both SO_2 and particulate matter emissions which would result in a cost savings.

The DOE and others believe that the proposed standard of .03 lb/MMBtu will preclude the use of ESPs on facilities using

> low-sulfur coal and require baghouse control which they believe has not been demonstrated on utility-size facilities. Because of this DOE recommends that the standard be no less than .05 lb/MMBtu. The Utility Air Regulatory Group also maintains that baghouses have not been adequately demonstrated, particularly when using high-sulfur coal. They further believe that ESPs cannot achieve the proposed standard of .03 lb/MMBtu at reasonable cost. In view of this, UARG recommends an emission limitation of .08 lb/MMBtu . . .

In the case of SO_2 uncontrolled emission levels can easily be calculated from the sulfur content of the fuel. This is not the case for particulate emissions, which can be affected many factors such as boiler ash retention, and emissions of carbon and sulfate. With respect to this problem EPA responded in conjunction with the NSPS proposal: [46]

> The 1977 amendments require that EPA specify, in addition to an emission limitation, a percent reduction in uncontrolled emission levels for fossil fuel-fired stationary sources. The proposed standard would require a 99-percent reduction for solid fuels and a 70-percent reduction for liquid fuels. Because of the difficulty of sampling particulate matter upstream of the control device (due to the complex particulate matter sampling conditions), the proposed standard would not require direct performance testing for the particulate matter reduction level. The percent reduction is not controlling, and performance testing for the emission limitation would satisfy the requirements for performance testing.

In fact, using typical emission levels for solid and liquid fuels, the percentage reduction levels are equivalent to the emission limitation levels.

The EPA NSPS proposal calls for a reduction in the allowable NO_x emissions to 0.6 lb/MMBtu for bituminous coal and to 0.5 lb/MMBtu for subbituminous coal from the previous permitted level of 0.7 lb/MMBtu. The proposal would leave the 0.3 lb/MMBtu level allowed for liquid fuels unchanged. EPA claims the new standard can be achieved through combustion and boiler modifications, and cites tests at various facilities to support their claim. UARG has expressed concern that since only the Combustion Engineering tangential fired boiler is presently capable of achieving the proposed standard, an anticompetitive condition could exist [47]. UARG has proposed that the present standard remain in effect.

The applicability of the proposed NSPS is detailed in the draft regulation, 40 CFR Part 60, subpart Da; [48]

> (a) The affected facility to which this subpart applies is each electric utility steam generating unit:
>
> (1) Which is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and
>
> (2) For which construction or modification is commenced after September 18, 1978.

The term modification is carefully defined in the proposed NSPS support document [49].

> In general terms, a modification is a selected type of change which increases the emission of selected pollutants to the atmosphere. When the alterations are limited, new source performance standards only

> require that increases in the emission of selected pollutants be prevented. In general terms, reconstruction is a change which is so substantial as to class the source as a new source rather than an altered existing source. In this case, the source becomes subject to all the limits of the new source performance standard.

The modification provision is defined to apply to only specific components of a power plant, and does not restrict the use of alternative fuels which the facility was designed to accommodate.

Practically, the modification rule will only apply to plants which convert to the use of a more polluting fuel for which they were not previously equipped without the special exemption provided for by ESECA or the Fuel Use Act [49].

> . . . Section 111(a)(8) of the Clean Air Act as amended in 1977, exempts from the modification provisions of the Act certain sources switching from oil or gas to coal. The latter category of sources is described in general terms as sources required to switch to coal under Section 2(a) of the Energy Supply and Environmental Coordination Act of 1974.

A facility is declared reconstructed, and therefore subject to the NSPS standard when: [49]

a. the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable new facility and,

b. it is technologically and economically feasible to meet applicable standards.

The new source performance standard proposed on September 18, 1978 was promulgated with minor revisions in the June 11, 1979 edition of the Federal Register [50]. The particulate emission standard of .03 lb/MMBtu was promulgated unchanged from the proposed standard, with some questions raised as to the possibility of a sulfuric mist interference with particulate matter testing. Until a more thorough investigation of the problem can be conducted utilities burning high sulfur fuels are permitted to test for particulate emissions ahead of flue gas desulfurization equipment [51]. Compliance with the particulate emission standard is determined through compliance testing, providing roughly a 2 hour average.

The NO_x standard was promulgated essentially the same as the proposal, with four levels of NO_x emission permitted depending on the type of fuel utilization. Unlike the proposal, the final NO_x standard permits compliance to be based on a monthly average rather than a 24 hour average. The EPA found this change warranted by the normal fluctuations encountered in boiler operation [52].

A compromise was struck between the various SO_2 reduction proposals, with the emergence of dry SO_2 scrubbing techniques significantly affecting the deliberation. The preamble to the promulgation of the new standard states: [53]

> The question was made more complex by the emergence of dry SO_2 control systems. As a result of public comments on the discussion of dry SO_2 control technology in the proposal, the EPA staff examined the potential of this technology in greater detail . . .
>
> Activity in the dry SO_2 control field is being stimulated by

several factors. First, dry control systems are less complex than wet technology. These simplified designs offer the prospect of greater reliability at substantially lower costs than their wet counterparts. Second, dry systems use less water than wet scrubbers, which is an important consideration in the Western part of the United States. Third, the amount of energy required to operate dry systems is less than that required for wet systems. Finally, the resulting waste product is more easily disposed of than wet sludge.

The applicability of dry control technology, however, appears limited to low-sulfur coals. At coal sulfur contents greater than about 1290 ng/J (3 lbs SO_2/MMBtu), or about 1.5% sulfur coal, available data indicate that it probably will be more economical to employ a wet scrubber than a dry control system.

Faced with these findings, the Administrator had to determine what effect the structure of the final resolution would have on the continuing development and application of this technology. A thorough engineering review of the available data indicated that a requirement of 90% reduction in potential SO_2 emissions would be likely to constrain the full development of this technology by limiting its potential applicability to high alkaline content, low-sulfur coals . . . In view of this, the Administrator sought a percentage reduction requirement that would provide an opportunity for dry SO_2 technology to be developed for all low-sulfur coal reserves . . . The Administrator concluded that a variable control approach with a minimum requirement of 70% reduction potential in SO_2 emissions (30-day rolling average) for low-sulfur coals would fulfill this objective.

Data used by EPA in assessing the potential impact of dry SO_2 scrubbing is contained in a recent EPA report, "Evaluation of Dry Sorbents and Fabric Filtration for FGD." [54]

Both the proposed and promulgated SO_2 emission standards for solid and solid derived fuels are illustrated in Fig. 1.1. The shaded region shows the degree to which the final standard is more lenient than the standard originally proposed. Unlike the proposed standard, compliance with the final standard is to be determined with continuous monitoring equipment calculated on a 30 day rolling average basis. Reductions obtained through fuel pretreatment of oil and coal are credited under the final standard. For nominal 10,000 Btu/lb coal Fig. 1.1 lists the equivalent sulfur content with respect to potential SO_2 emissions.

Figure 1.2 illustrates the SO_2 emissions permitted for plants burning gaseous and liquid fuels not derived from solid fuels. Similar to solid fuels, compliance is determined on a 30 day rolling average basis. Due to the influence of the Fuel Use Act, only a limited number of new sources will be built which will burn oil as a primary fuel. Nonetheless, for calibration purposes an equivalent sulfur content of oil is shown using a nominal value of 19,000 Btu/lb. Note that oil of 0.19%S content can be burned without the use of FGD scrubbing.

Special SO_2 emission standards are provided in the final regulations for anthracite coal and solid solvent refined coal. Both anthracite coal and solid solvent refined coal are permitted a 30 day average source emission rate of 1.2 lb/MMBtu, with solid solvent refined coal held to an 85% reduction in potential SO_2 emissions achieved at the refinery on a 24 hour averaging basis. No percentage reduction is required for anthracite coal, a measure likely to stimulate utilization. Anthracite with a heat value of 14,000 Btu/lb and .84% sulfur content can be burned without the use of FGD scrubbing.

4. Prevention of Significant Deterioration, Visibility Protection

On December 6, 1974, EPA published regulations under the 1970 version

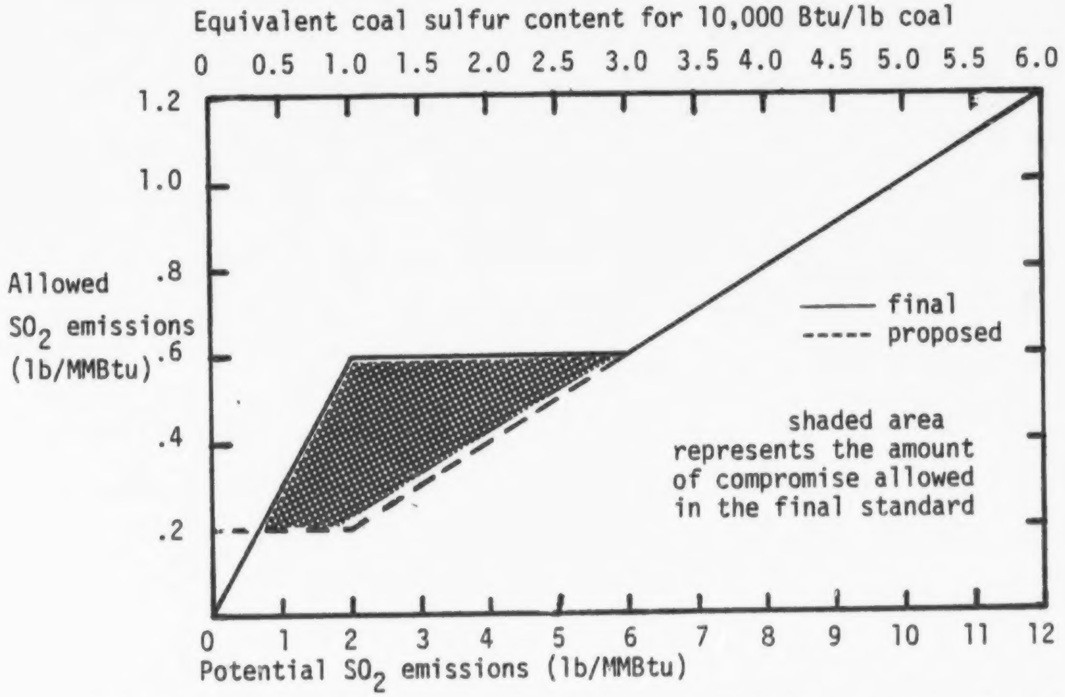


Fig. 1.1 New source proposed and final allowed SO_2 emissions for plants burning solid and solid derived fuels. Computed by 30 day rolling average.

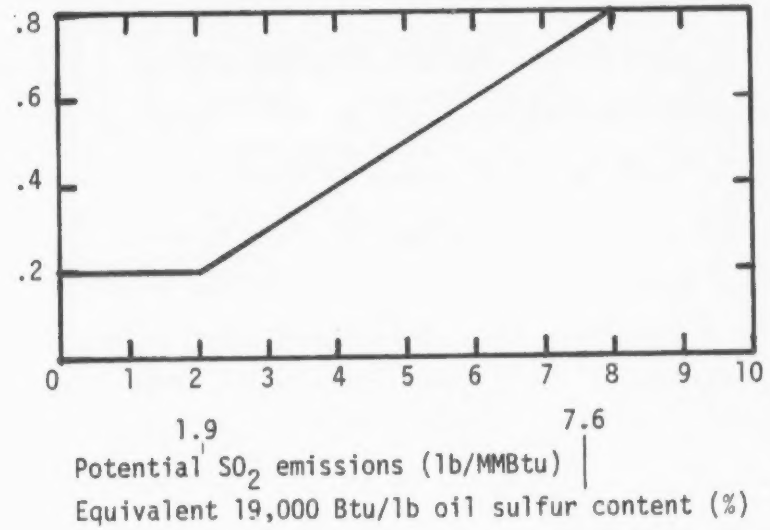


Fig. 1.2 New source allowed SO_2 emissions for plants burning gaseous and liquid fuels. Computed by 30 day rolling average.

of the CAA for the prevention of significant deterioration of air quality (PSD). These early regulations initially designated all clean air areas of the country (those not in violation of the NAAQS) as class II, with mechanisms set up for the reclassification of areas as either class I or class III. Class I areas permitted only minor air quality deterioration, class II areas allowed moderate deterioration, and class III areas allowed deterioration up the secondary NAAQS.

The PSD Program was strengthened and provided with a firm legislative backing by the 1977 CAA amendments. Sections 160 to 169 of the amended act deal with the PSD program. Section 160 lists the five purposes of the PSD program, the first being:

> (1) to protect the public health and welfare from any actual or potential adverse effect which in the Administrator's judgement may reasonably be anticipated to occur from air pollution or from exposure to pollutants in other media, (which pollutants originate as emission in the ambient air), notwithstanding attainment and maintenance of all national ambient air standards;

The amended PSD program differs from the existing program in many ways, including the creation of mandatory class I areas, a reduction in the allowable increments, and an increase in the number of sources eligible for PSD review.

Mandatory class I areas are defined in Sec. 162 of the CAA:

> (1) international parks
> (2) national wilderness areas which exceed 5,000 acres in size
> (3) national memorial parks which exceed 5,000 acres in size, and
> (4) national parks which exceed 6,000 acres in size . . .

A list of mandatory class I areas can be found in the Federal Register [55]. This list does not contain any areas in Massachusetts or Connecticut, but contains areas in New Hampshire and Vermont.

Air quality increments are specified in the CAA for SO_2 and TSP. An increment is defined as the final total increase allowed in an ambient pollutant level. The increment is defined wiht respect to a baseline concentration, essentially the ambient level in existence since January 6, 1975 [56]. Air quality increments for criteria pollutants other than SO_2 and TSP must be developed and promulgated by the Administrator before August, 1979 under Sec. 166 of the CAA. Air quality increments specified in the CAA by PSD class are listed in Table 1.9

TABLE 1.9

PSD Permitted Increments ($\mu g/m^3$)

	Class I	Class II	Class III
SO_2 Annual	2	20	40
24-hour	8	91	182
3-hour	25	512	700
TSP Annual	5	19	37
24-hour	10	37	75

Section 169(1) of the CAA defines "major emitting facility". those facilities which must undergo a PSD review to commence new construction or conduct a major modification. This term refers to a list of 28 specific sources including power plants which have uncontrolled emissions of any regulated pollutant greater than 250 tons/yr. Final EPA regulations amending Title 40 Section 52.21 of the Code of Federal Register and adding Titel 40 Section 51.24 are published in the June 19, 1978 Federal Register [57]. These new regulations implement the PSD program stipulated by the 1977 CAA amendments and were initially proposed November 3, 1977 followed by public comment period and hearing. Comments were received from the

Energy Department, the President's economic advisors, and most significantly from an association representing local air pollution enforcement units; the State and Territorial Air Pollution Program Administrators (STAPPA). STAPPA expressed concern that local agencies would be unable to handle the extensive PSD review process for the large number of sources stipulated by the CAA. STAPPA recommended that the PSD review process be triggered only for sources with controlled emissions of over 50 tons/yr.

The PSD review process is stipulated in Sec. 165(a) of the CAA:

> (a) No major emitting facility on which construction is commenced after the date of the enactment of this part may be constructed in any area to which this part applies unless--
>
> (1) a permit has been issued for such proposed facility in accordance with this part setting forth emission limitations for such facility which conform to the requirements of this part;
>
> (2) the proposed permit has been subject to a review in accordance with this section, the required analysis has been conducted in accordance with regulations promulgated by the Administrator, and a public hearing has been held with opportunity for interested persons including representatives of the Administrator to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations;
>
> (3) the owner or operator of such facility demonstrates, as required pursuant to section 110(j), that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum

allowable concentration for any pollutant in any area to which this part applies more than one time per year, (B) national ambient air quality standard in any air quality control region, or (C) any other applicable emission standard or standard of performance under this Act;

(4) the proposed facility is subject to the best available control technology (BACT) for each pollutant subject to regulation under this Act emitted from, or which results from, such facility;

(5) the provisions of subsection (d) with respect to protection of class I areas have been complied with for such facility;

(6) there has been an analysis of any air quality impacts projected for the area as a result of growth associated with such facility;

(7) the person who owns or operates, or proposes to own or operate, a major emitting facility for which a permit is required under this part agrees to conduct such monitoring as may be necessary to determine the effect which emissions from any such facility may have, or is having, on air quality in any area which may be affected by emissions from such source; and

(8) in the case of a source which proposes to construct in a class III area, emissions from which would cause or contribute to exceeding the maximum allowable increments applicable in a class II area and where no standard under section 111 of the Act (NSPS) has been promulgated subsequent to enactment of the Clean Air Act Amendments of 1977, for such source category, the Administrator has approved the determination of best available technology as set forth in the permit.

A review article by ERT on the impact of the 1977 amendments on permit proceedings estimates that point 7 above will stretch the time required to receive a permit to between 21 and 43 months [58]. In response to the comments received and an economic impact study conducted for the proposed regulations, EPA decided, "In light of section 165(b) and these findings, EPA has decided generally to exempt from full PSD review any new major stationary source or major modification which would have allowable emissions of less than 50 tons per year, 1,000 pounds per day, or 100 pounds per hour, whichever is more restrictive . . . In accordance with the decision, under Sec. 52.21(j), no 50-ton source need apply BACT in order to get a PSD permit . . . Under Sec. 52.51(k), no applicant for a PSD permit for a 50-ton source would have to demonstrate that the source would cause or contribute to a violation of an applicable increment or NAAQS. [59] . . . The definition of BACT is provided in Sec. 169(3) of the CAA:

> The terms "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act, emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable for such facility through application of production processes...

Application of BACT is further defined to be as stringent or more stringent than the application of Sec. 111 new source performance standards.

EPA announced in the November 3, 1977 proposed regulations that new PSD requirements would not go into effect starting August 7, 1977 as specified in the CAA. Sources which received permits before March 19, 1979 are regulated by the previous PSD requirements, and sources not meeting these deadlines are regulated by the newer and more stringent PSD requirements [60]. States are required under the new regulations to submit revised State Implementation Plans (SIP) incorporating the PSD program requirements by March 19, 1979. Legal enforcement of the PSD program is similar to NSPS regulations, with the EPA retaining the right to revise and enforce the state PSD implementation plan.

Part 51 of the amended Code of Federal Register contains regulations for the states in drafting state PSD programs. These regulations permit the states to require emissions reductions from existing sources, to establish a marketable permit program, and establish emissions density zoning. These programs are explained with the proposed regulations [61].

Subpart 2, Part C (PSD) of the CAA is entitled, "Visibility Protection for Federal Class I Areas." Section 169A(a)(1) states, "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." Section 169A(a)(3) states:

> Not later than eighteen months after the date of enactment of this section, the Administrator shall complete a study and report to Congress on available methods for implementing the national goal set forth in paragraph (1). Such report shall include recommendations for--
>
> (A) methods for identifying, characterizing, determining, quantifying, and measuring visibility impairment in Federal areas referred to in paragraph (1), and
>
> (B) modeling techniques for determining the extent to which

> manmade air pollution may reasonably be anticipated to cause or contribute to such impairment, and
>
> (C) methods for preventing and remedying such manmade air pollution and resulting visibility impairment.

The list of class I Federal areas for which visibility is deemed an important value was promulgated in the Federal Register on February 12, 1979 [55]. This list includes 156 of the 158 mandatory PSD class I area. No class I Federal areas exist in Massachusetts or Connecticut.

The report due to be delivered to Congress was not delivered as of March, 1979. A March review article on the visibility questio states, "The report to Congress was due last month, but the deadline was missed because the contractor's draft was inadequate. EPA is making extensive revisions to the report, which will rely, in part, on the content of the CEQ study." [62]

The Federal Register issue which promulgated the list of class I areas for visibility protection states: [55]

> Examination of the legislative history of the visibility provision indicates that Congress was concerned about evidence submitted by environmental groups, such as the National Parks and Conservation Association, indicating, "there is evidence that some areas that in the past had 100-mile visibility, now have only an average of 30-mile visibility. Much of this can probably be attributed to emissions from power plants, such as the Navaho and Four Corners plants." In addition to the recognized threat of power plants to long-range visibility in the western United States, Congress also was concerned that the hazes found in high vegetation areas of the South-East "are not dominated

> by natural organic compounds, but by sulfate aerosol particles probably from the oxidation of SO_2 emitted from regionally distributed sources" . . Congress noted that the current national ambient air quality standards were not adequate to protect visibility in Federal mandatory class I areas.

The seriousness with which Congress viewed the visibility question can be judged from the requirement for BART in Sec. 169A(b)(2):

> (2) require each applicable implementation plan for a State in which any area (in or affecting class I visibility areas) . . . to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal specified in subsection (a), including--
>
> (A) except as otherwise provided pursuant to subsection (c), a requirement that each major stationary source which is in existence on the date of enactment of this section, but which has not been in operation for more than fifteen years as of such date, and which, as determined by the State (or the Administrator in the case of a plant promulgated under section 110(c)) emits any air pollutant which may reasonably be anticipated to cause or contribute to impairment of visibility in any such area, shall procure, and operate, as expeditiously as practicable (and maintain thereafter) the best available retrofit technology (BART) as determined by the State (or the Administrator in the case of a plan promulgated under section 110(c)) . . ., and
>
> (B) a long term (ten to fifteen years) strategy for making reasonably progress toward meeting the national goal specified in

subsection (a)).

Definitions for visibility protection are provided in Sec. 169A(g). A "major stationary source" is defined as one of a list of facilities, including power plants with more than 250 million BTU/hr input, with the potential to emit 250 tons or more per year of any pollutant. In determining BART this section states the authorities "shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

There seems to be little dispute that visibility impairment is the result of primarily fine particles and NO_2 gas in the atmosphere. Questions surround the mechanisms for generation and dispersion of fine particles. A book entitled Airborne Particles recently released by the National Academy of Science (NAS) states, "The fine particles between 0.1 and 1.0 μm diam. consist mainly of sulfates from sulfur dioxide oxidation, nitrates from NO_x reactions, ammonium from ammonia reactions, condensed organic matter (partially oxygenated), and primary emitted particles, such as lead and carbon." [63] Ash significantly, is absent from this list. Modeling work by Dr. Whitby in this volume attempts to model the atmospheric generation of fine particles from gas phase constituents.

The Natural Resources Defense Council (NRDC) has recently completed a major study on the effects of fine particles, and should play a significant role in the upcoming debate [64]. The NRDC blames fine particle for both health and visibility effects, and essentially agrees with the NAS on the sources of this material. "Each year more than five million tons of man-made primary fine particles--such as soot, fly ash, condensed metals, and vapors--are unloaded into the atmosphere. However, the majority of particles in urban areas--about 60 to 80 percent-- are "secondary" in nature; that is, they are formed from gaseous precursors in the atmosphere." The NRDC advocates enhanced control of both fine particle and gas phase emissions.

A recent APCA conference on atmospheric sulfate was attended by EPA aerosol expert John Bachmann [65]. The report on this conference states, "According to John Bachmann from EPA's Office of Air Quality Planning and Standards, recent toxicological and chemical evidence shows that health effects from sulfuric acid and other sulfates occur at levels significantly higher than those typically observed in the ambient atmosphere. Consequently, EPA has no plans to set a primary standard for sulfates. Instead, the EPA is focusing their research efforts in two direction: development of an inhaled-particulate standard and consideration of a secondary sulfate standard based on visibility degradation and/or precipitation acidity." Bachmann reports visibility, "decreased between 10 to 40% at nonurban sites (from the mid-'50s to the early 1970's) to the point where nonurban visibility was not substantially better than urban visibility." This result highlights the importance of long-range transport. From the same conference, "Other EPA studies indicate that sulfate may be the principal cause of air pollution-related visibility reduction in areas as diverse as the eastern United States, the Southwest, and the Los Angeles basin. Regression models attribute 50% of the total visibility reduction in the northeastern U.S. to sulfates."

The CEQ report "Visibility Protection for Class I Areas: The Technical Bases" reports that the atmospheric light extinction coefficient is directly proportional to the fine particle concentration when the relative humidity is below 70%. Figure 1.3 illustrates the relationship between visibility and fine particle concentration [66]. The CEQ recommends that neither a Sec. 169 (of the CAA) optical standard nor a Sec. 109 ambient fine particle standard can be proposed now because each is technologically and economically infeasible for northeastern states to meet. It is suggested that an ambient fine particle standard (less than 2 μm) may be promulgated in 1984 or 1985 however,

An EPA study reports that during a nine-month copper strike in 1967-1968 sulfate aerosols declined by 38 - 76% at five federal monitoring sites within 70 miles of the smelters, and visibility simultaneously improved by 5 - 25% within 150 miles of the smelters. Weather patterns reportedly could not account for the improvement [62]. Visibility protection is becoming a significant issue in national environmental policy.

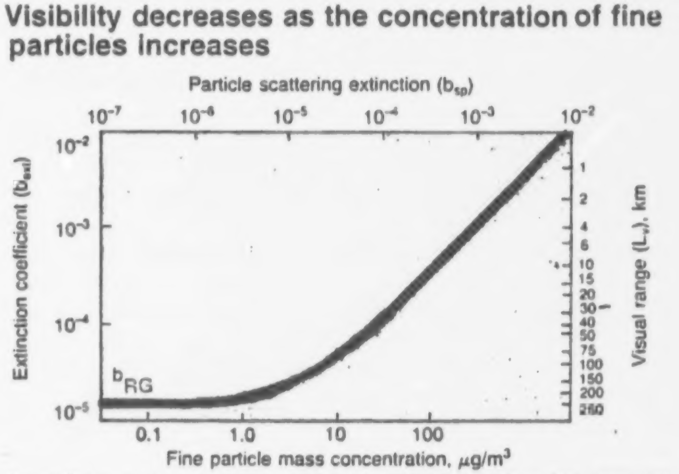
5. Power Plant and Industrial Fuel Use Act of 1978

Congress enacted the Energy Supply and Environmental Coordination Act on June 24, 1974 (ESECA) [67]. This act, amended in 1975 and 1977 contained a statement explaining its purpose in Sec. 1(b):

> The purposes of this Act are (1) to provide for a means to assist in meeting the essential needs of the United States for fuels, in a manner which is consistent, to the fullest extent practicable, with existing national commitments to protect and improve the environment and (2) to provide requirements for reports respecting energy resources.

Section 2 of the act, entitled, "Coal conversion and allocation" states:

> (A) The Federal Energy Administrator -- (1) shall, by order,



*Source: Charlson et al Visibility Protection for Class I Areas: The Technical Basis. CEQ, August 1978

FIGURE 1.3

Plot of visibility decrease with concentration of ambient fine particulate.

> prohibit any major fuel burning installation, other than a power plant, from burning natural gas or petroleum products as its primary energy source, if the requirements of subsection (b) are met and if (A) the Federal Energy Administrator determines such powerplant or installation on June 22, 1974 had, or thereafter acquires or is designed with, the capability and necessary plant equipment to burn coal, or (B) such powerplant or installation is required to meet a design or construction requirements under subsection (c).

ESECA provides many requirements which the Federal Energy Administrator (now the Secretary of Energy) must satisfy before he is permitted to issue a prohibition order. The Administrator must find that the burning of coal is practical, that coal transportation facilities are available, that the reliability of service will not be impaired by the order, and the Administrator of the EPA must certify that coal can be burned at the facility without violating applicable air pollution requirements.

A report from the New England Energy Task Force states with respect to the issuance of a prohibition order [68], "For the DOE and the EPA, issuance of a Prohibition Order (under ESECA) initiates a complex review procedure." This procedure is detailed in Title 10, Parts 303 and 305 of the Code of Federal Regulation and is summarized in the Energy Task Force report: [68]

> A company first learns it has units under consideration for an ESECA Prohibition Order (PO) through issuance by DOE of a "Notice of Intent" to issue a PO. Following public hearing and DOE review, the DOE issues the PO. The EPA must then certify the date by which the plant can comply with existing emission limits and not cause violation of national ambient air quality standards. Meanwhile, the

DOE develops an environmental impact statement (EIS) for the plant. Once it has received EPA certification for a date for compliace (or of an estimated but uncertified date), DOE may publish the EIS along with the proposed certification date and hold public hearings again. If it still finds conversion to be practicable within the definitions of ESECA, the Department issues a Notice of Effectiveness for the Prohibition Order.

Considering the complex nature of this procedure, it is not surprising that only one conversion is underway as of 1979. Eleven units at five generating stations in the New England area have received DOE prohibition order. These stations are listed in Table 1.10 [68].

TABLE 1.10

Prohibition Orders Issued in the New England Area

Plant	Location	Convertible Capacity (MW)
Brayton Point	MA	1,140
Middletown	CT	422
Norwalk Harbor	CT	326
Mount Tom	MA	150
Schiller	NH	100

Of these five units, only Brayton Point has responded by negotiating with the regulatory agencies and agreeing to a program of voluntary conversion. The Brayton Point agreement is discussed in more detail later in this section.

The authority granted to the DOE Secretary for issuing orders under

ESECA expired on December 31, 1978, although orders previously issued under the act may take effect up till January 1, 1985 [69]. The authority for coal conversion programs has shifted from ESECA to the National Energy Act, which becomes effective on May 8, 1979. This act, passed by Congress on October 15, 1978 consists of five bills, with the "Powerplant and Industrial Fuel Use Act of 1978" legislating coal conversion [70]. Section 102 of the Powerplant and Industrial Fuel Use Act (FUA) states the findings of Congress with respect to the act:

> (a) The Congress finds that--
>
> (1) the protection of public health and welfare, the preservation of national security, and the regulation of interstate commerce require the establishment of a program for the expanded use, consistent with applicable environmental requirements, of coal and other alternate fuels as primary energy sources for existing and new electric powerplants and major fuel-burning installations; and
>
> (2) the purposes of this Act are furthered in cases in which coal or other alternate fuels are used by electric powerplants and major fuel-burning installations, consistent with applicable environmental requirements, as primary energy sources in lieu of natural gas or petroleum.

The FUA is broken down into nine titles, with Title II covering new facilities and Title III dealing with existing facilities. A significant volume of regulation has been proposed by the Economic Regulatory Administrations (ERA) of the DOE to enforce FUA. In the background section to the proposed implementation rules ERA states: [71]

> ESECA authorized DOE to prohibit certain powerplants and installations

from burning petroleum and natural gas and to order certain powerplants and installations in the "early planning process" to be built with coal burning capability. Before DOE could issue any order under ESECA it had to make detailed technical findings. The burden of proving these findings for each order was placed upon DOE. In addition, the order was not effective under ESECA until DOE has completed a three-stage administrative process.

Under FUA, DOE can establish a more effective and comprehensive program. In contrast with the provisions of ESECA, FUA itself prohibits the use of petroleum and natural gas by certain powerplants. FUA also authorizes DOE to prohibit by rule or by individual order the use of natural gas or petroleum by certain other powerplants and installations. FUA also establishes a process by which DOE may exempt a powerplant or installation from any prohibition if certain criteria are met. The burden of proof of demonstrating that an exemption is warranted rests on the petitioner requesting the exemption and not on DOE.

Title II, Subtitle A, Sec. 201 of the FUA states the prohibitions applicable to new powerplant facilities;

> Except to such extent as may be authorized under subtitle B-- (1) natural gas or petroleum shall not be used as a primary energy source in any new electric powerplant; and (2) no new electric powerplant may be constructed without the capability to use coal or any other alternate fuel as a primary energy source.

Subtitle B of Title II lists the exemptions for which new facilities are eligible.

Title III, Subtitle A, Sec. 301 of the FUA states the prohibitions applicable to existing powerplants. Subsection (a) states a mandatory prohibition on the use of natural gas, a fuel not widely employed in the New England area. Subsection (b) gives the Secretary of Energy discretionary authority to force conversions to coal or other alternative fuels. This subsection states:

> The secretary may prohibit, in accordance with section 303(a) or (b), the use of petroleum or natural gas, or both, as a primary energy source in any existing electric powerplant, if the Secretary finds that--
>
> (1) such powerplant has or previously had the technical capability to use coal or another alternate fuel as a primary energy source;
>
> (2) such powerplant has the technical capability to use coal or another alternate fuel as a primary energy source, or it could have such capability without--
>
> (A) substantial physical modification of the powerplant, or
>
> (B) substantial reduction in the rated capacity of the powerplant; and
>
> (3) it is financially feasible to use coal or another alternate fuel as a primary energy source in such powerplant. The requirement of paragraph (1) shall not be considered to be satisfied unless the finding under such paragraph is made before the date of the publication of the notice of proposed prohibition under section 701(b) and is published with such notice.

Subparagraph (c) gives the Secretary of Energy authority to prohibit the excess consumption of petroleum or natural gas when fuel mixtures can be employed, above that required for reliability and efficiency.

The discretionary status of the petroleum prohibition for existing units makes a study of the exemption system, as stipulated in the law and the subsequent regulation, essential for judging the impact of the FUA. The prohibition order for new powerplants should not have a significant impact on the utility industry since economic considerations alone dictate that most future units will probably be designed to burn coal. The impact of FUA on units picked for this study is an important consideration in judging their future air pollution control requirements. Both ESECA and FUA stipulate that units convert to coal and stay in compliance with the CAA. Section 761(a) of the FUA states, "Except as provided in section 404 nothing in this Act shall be construed as permitting any existing or new electric powerplant or major fuel-burning installation to delay or avoid compliance with applicable environmental requirements," Section 404 refers to the authority granted to the Governor of a state under 110(f) of the CAA to suspent parts of the state's implementation plan. This suspension can last for a period of up to four months, and can only be issued with the approval of the President and the concurrence of the EPA Administrator.

Section 303 of FUA lists the two types of prohibition actions available to the Secretary of Energy for existing facilities. Subsection (a) stipulates that case-by-case orders can only be issued through a ruling procedure, and that case-by-case prohibitions should give precendence to prohibitions by category of facilities. Subsection (b) stipulates that regulations can be drafted which identify categories of facilities with fuel heat input rates of 300 million Btu's per hour or greater for prohibition of petroleum and natural gas usage. The regulations and a listing of the facilities to be affected must be published in the Federal Register. The Secretary is instructed to take individual circumstances into account when drafting the regulations, and rules do not take effect until requests for exemptions and judicial review have been resolved. Requests for exemptions and judicial review must be filed within 60 days of the publication of final rules in the Federal Register. The discretionary nature of the petroleum prohibition order implies that ERA may begin prohibition proceedings against a facility as soon as regulations are promulgated and as late as the repeal of FUA.

The ERA published proposed implementation rules for existing facilities in the January 29, 1979 issue of the Federal Register [72]. In the supplementary information section of this proposal ERA explains the findings which must be made before a prohibition order is issued: [73]

> Prior to issuing a final order prohibiting a powerplant or installation from burning petroleum or natural gas as a primary energy source, we must find that: the unit is or previously was technically capable of burning an alternate fuel; the unit can burn that fuel without a substantial physical modification to, or derating or, the unit; and it is financially feasible to use an alternate fuel.
>
> In making our technical capability finding, we propose to assume that units are capable not only of burning the fuels for which they were specifically designed, but that certain units are also technically capable of burning selected alternate fuels which were not included in the purchaser's design specifications. For example, units capable of burning natural gas are also technically capable of burning other gaseous fuels such as gas derived from coal. Similarly, units constructed as to be capable of burning petroleum are also inherently capable of burning alcohol from coal.
>
> In assessing whether a "substantial physical modification" would occur as a result of converting to an alternate fuel, we propose to

consider the conversion feasible if the unit has the requisite furnace configuration and tube spacing. Adjustments required to install pollution control equipment such as precipitators or scrubbers generally will not be viewed as substantial modifications to the unit.

We propose that a derating of less than 25 percent of a unit's design capacity will not be considered "substantial". These proposed regulations stipulate that any reduction in useful capacity resulting from the addition of pollution control equipment to the unit will not be included in computing the level of derating. However, where alternate sources of energy are available to operate pollution control equipment required for a particular unit, ERA may consider the cost of using such alternate energy in its cost calculation.

The "financial feasibility" criteria are composed of both a unit-specific evaluation identical to the "substantially exceeds" cost calculation test and an assessment of the affected firm's capability to raise the necessary capital to finance the conversion.

This statement of policy lends a strong tone to the determination of eligibility for conversion. Especially significant is the very minimal consideration given to potential utility requirements for additional pollution control equipment, and the statement that a 25% reduction in unit capacity due to conversion would not be considered "substantial".

The implementation rules for existing facilities are proposed to become Part 504 of 10 CFR, Chapter II, Subchapter E. The proposed Part as written minimizes the distinction between case-by-case and category Sec. 302 (FUA dealing with existing facilities) prohibitions. Section 504.5 of the proposed regulations is entitled "Prohibitions by order (case-by-case)".

This section reiterates the discretionary nature of the existing plant prohibition for petroleum through the consistent use of the word "may". In regulatory language Sec. 504.5 repeats the conditions for prohibition from FUA and the interpretations previously cited from the supplementary information section. ERA states that the question of financial feasibility is determined by the cost calculation described in Sec. 504.12 and the ability to raise capital. The ability of utilities to raise capital is enhanced by Sec. 602 of FUA. This section provides $400,000,000 in fiscal 1979 and an equal amount in fiscal 1980 to assist the utilities in purchasing air pollution control equipment. Section 504.5 of the regulations provides that before a prohibition order can be issued for a facility a notice must be published in the Federal Register, and during the subsequent period of at maximum 49 days the utilities have the opportunity to challenge ERA findings. Section 504.5, paragraph (h) states:

> (h) ERA may not issue a final order to your powerplant if you demonstrate by written submission that your facility would be eligible for an exemption under the criteria set out in this part for any applicable exemption, or if you have demonstrated to the satisfaction of ERA that the required findings stated in paragraph (a) of this section cannot be made. However, if your powerplant would be eligible only for a temporary exemption, ERA may issue you a final order that will take effect at the expiration of the temporary exemption.

The definition of primary energy source is provided in the proposed regulations: [74]

> "Primary Energy Source" means the fuel or fuels used for normal operation by any existing or new electric powerplant or major fuel

> burning installation, except--
>
> i. Minimum amounts of fuel required for unit ignition, startup, testing, flame stabilization and control use;
>
> ii. Minimum amounts of fuel required to alleviate or prevent unanticipated equipment outages and emergencies directly affecting health, safety or welfare which would result from electric power outages; . . .

Cost calculations will serve an important role in determining whether a plant receives a prohibition order. Section 504.12 of the proposed regulations is entitled "Cost calculations for existing powerplants [75]. This section provides formulas for cost calculations to be used in applications for both temporary and permanent exemptions. The General Cost Test calculates the cost of using an alternate fuel for the remaining life of a facility. Alternate fuel is defined with the proposed regulations as any of a number of fuels such as coal, low-gravity crude, heavy oil sands, tar sands, and any other fuel which would help to increase the nation's supply and decrease its dependence on foreign sources. The Special Cost Test is calculated by assuming that conversion to an alternate fuel would occur at different times as late as ten years from the present. This calculation is appropriate for applications to receive temporary exemptions. The form of the equations for both the general and special cost calculations are the same, and they are both qualified by the following footnote: [76]

> The electric power industry is a regulated industry. Its profits depend upon its regulators as well as its costs. Since there are many regulatory bodies, which do not always act the same way, we decided not to be concerned with the profits, per se, but only with the costs to society of producing electricity. The income taxes

paid by the utilities are transfer payments, from a societal point of view, and therefore are not included in the calculation.

Consequently, the equation for cost is straightforward and is shown here as Eq. 1.1.

$$\mathrm{COST} = I + \frac{OM_1 + FL_1}{1+K} + \frac{OM_2 + FL_2}{(1+K)^2} + \cdots + \frac{OM_N + FL_N}{(1+K)^N} - \frac{S_p}{(1+K)^P} \qquad (1.1)$$

COST ≡ The total discounted cost in dollars, of constructing and operating the plant for the remaining useful life of the powerplant.

I ≡ Discounted total net capital outlay in dollars, excluding investment tax credits amd "Advances in Aid of Construction" (as per FERC system of accounts). May include investment in additional transmission facilities to deliver power to your service area. (ERA will not consider investment tax credits for oil or gas fired powerplants.)

OM ≡ Annual cost in dollars of operating and maintaining the unit starting when the exemption becomes effective. May include expenditures for wheeling power to your service area.

S_p ≡ Salvage value of equipment rendered useless by changing the fuel from oil or natural gas to alternate fuel in year p.

FL ≡ Annual delivered fuel expenditures in dollars starting when the exemption becomes effective.

P ≡ Year fuel is changed from oil or natural gas to alternate fuel.

K ≡ The real cost of capital expressed as a fraction.

N ≡ The remaining useful life of the powerplant

The remaining useful life of a powerplant is defined as 35 years minus the years of operation prior to the effective exemption date, with special circumstances taken into consideration. The cost of capital for an electric utility is defined as 3.5% per year in real terms, equivalent to an interest rate of 3.5% plus the rate of inflation.

Costs must be calculated for the various alternate fuels and for each case, with its own proposed starting date, the ratio of this calculation must be taken to the result of the same calculation using petroleum as the fuel. This ratio is defined as R, the ratio of the cost of using an alternate fuel to the cost of using imported petroleum. This ratio plays a central role in determining whether an existing powerplant will receive an exemption from prohibition. With respect to this ratio ERA states: [75]

> The cost of using an alternate fuel in lieu of imported petroleum as a primary energy source, or the cost to use an alternate power supply will be deemed to be substantially in excess of the cost to use imported petroleum where the ratio of the former to the latter is greater than the index set periodically by ERA. Initially, ERA sets the index at (1.5). ERA will revise the index from time to time after public notice and an opportunity to comment. Revisions shall become effective for all ERA decisions after final publication.

The employment of the ratio is further explained:

> If all the ratios (R) are greater than, for illustrative purposes, 1.5 (an index to be set periodically by ERA), your exemption

would be granted. If one or more of the ratios (R) is equal to or less than 1.5 and a series of ratios (R), starting with the case where alternate fuel is used for the start of operation, are all greater than 1.5, a temporary exemption would be granted for the minimum period in which the cost of starting to use an alternate fuel, deferred year by year, always exceeds (1.5).

Although the prohibition for petroleum use by existing facilities is declared discretionary by the FUA and controlled by the ERA, the exemptions to this prohibition are of four types, both mandatory and discretionary, temporary and permanent. The rules for exemptions to prohibitions for existing facilities are mandated in Title III, Subtitle B of the FUA with subsequent regulation appearing in the January 29, 1979 Federal Register proposed to become Part 504 of 10CFR, Chapter II, Subchapter E. The proposed part 504 is entitled, "Existing Electric Powerplants" [77]. The requirements for exemptions listed in the act are repeated and clarified in the proposed regulation. Entitled general policy, the proposed regulations provide the following outline of the types and requirements for the single lettered potential exemptions. The appropriate section numbers and mandatory demonstrations shown in parentheses have been added by the author:

Mandatory temporary exemptions for existing facilities

AA. (Use of mixtures, Sec. 504.14)

A. Lack of alternate fuel supply, Sec. 504.21

B. Site limitations, Sec. 504.22

C. Environmental requirements, Sec. 504.23

D. Use of synthetic fuels, Sec. 504.24

E. Use of innovative technologies, Sec. 504.25

F. Units to be retired, Sec. 504.27

G. Peakload powerplants, Sec. 504.29

H. Reliability of service, Sec. 504.28

Discretionary temporary exemptions for existing facilities

AA. (Use of mixtures, Sec. 504.14)

A. Public interest, Sec. 504.26

Mandatory permanent exemptions for existing facilities

AA. (Use of mixtures, Sec. 504.15)

AB. (Use of fluidized bed, Sec. 504.16)

A. Lack of alternate fuel, Sec. 504.31

B. Site limitations, Sec. 504.32

C. Environmental requirements, Sec. 504.33

D. Fuel mixtures, Sec. 504.36

E. Emergency purposes, Sec. 504.37

F. Peakload powerplants, Sec. 504.38

G. Powerplants with design capacity of less than 250 MMBtu/hr., Sec. 504.40

H. Use of LNG, Sec. 504.41

Discretionary permanent exemption for existing facilities

AA. (Use of alternative supply, Sec. 504.13)

AB. (Use of mixtures, Sec. 504.15)

AC. (Use of fluidized bed, Sec. 504.16)

A. State or local requirements, Sec. 504.34

B. Cogeneration, Sec. 504.35

C. Intermediate load powerplants, Sec. 504.39

Mandatory exemptions are provided "upon a satisfactory showing that the petitioner has met the required evidentiary burden." With respect to discretionary exemptions, "ERA may grant such exemptions if the petitioner meets the required evidentiary burden and ERA decides that it would be consistent with the Act, with national energy policy, and in the public interest to do so."

The time period for which temporary exemptions may be granted may not exceed five years by the authority of Sec. 302(h) of the FUA, and an extension may be granted by ERA to extend the period to not longer than ten years from the date from which the exemption would be required.

Temporary exemptions of either type will not be granted due to Sec. 504.14 of the regulations unless consideration is given to the use of mixtures. If ERA finds the use of mixtures to be technically and economically feasible, the temporary exemption will be conditioned on the use of that mixture during the period of the exemption.

A mandatory temporary exemption shall be granted under Sec. 504.21 if an alternative fuel supply cannot be found which provides a cost ratio, by the previously mentioned cost test, of less than 1.5. An applicant for this exemption must demonstrate that he will be able to comply with the provisions of FUA upon the expiration of the exemption.

A temporary exemption can be granted under Sec. 504.22 with appropriate documentation that one or more of the following site limitations exists:

1. Alternate fuels would be inaccessible;
2. Transportation facilities for alternate fuels would be unavailable
3. Adequate facilities for handling, using, or storing an alternate fuel would be unavailable;
4. Adequate means for controlling and disposing of wastes would be unavailable

5. Adequate and reliable supply of water would be unavailable; or
6. Other site limitations exist which would not permit the operation of the existing powerplant using an alternate fuel.

Evidence must be shown that action is being taken to overcome the site limitation at the end of the maximum five year exemption period.

Under Sec. 504.23 the ERA shall grant an exemption for a period not to exceed five years due to inability to satisfy Federal or State environmental requirements. Documentation must be provided that compliance will be achieved at the end of the five year period.

The future use of synthetic fuels is grounds for a temporary exemption under Sec. 504.24 if it is demonstrated that an alternate fuel cannot be utilized in the intervening period. The innovative technology to be utilized must be described to the ERA, along with economic and technical feasibility studies supporting the use of the alternate fuel and documenting compliance with FUA at the end of the exemption period. A similar exemption for the use of innovative technologies is described in Sec. 504.25.

The retirement of a unit within the five year period specified in Sec. 504.27 is grounds for a temporary exemption. The applicant must document that an alternate fuel cannot be utilized within the maximum five year remaining life of the plant.

An exemption for a period of as long as five years can be received if documentation is provided that a facility is used solely as a peakload powerplant. A peakload plant is defined as one which in any 12-calendar-month period does not exceed in generation the design capacity multiplied by 1,500 hours.

In the case that plant downtime or reduced load capability would jeopardize reliability of service an exemption of not to exceed ten years can be granted under Sec. 504.28. The loss of load probability technique (LOLP) is stipulated as the test for this exemption.

In order for a facility to receive a discretionary temporary exemption for the public interest, documentation must be shown that during the maximum five year period of the exemption fuel mixtures cannot practically be employed (Sec. 504.14). Three points must be demonstrated to ERA to receive this temporary exemption under Sec. 504.26 of the regulations:

1. You are unable to comply with the applicable prohibitions imposed by the Act, or order or rule issued by DOE, except in extraordinary circumstances, during the period for which the exemption is requested, but that you will be capable of complying at the end of the proposed exemption period;
2. You are not eligible for a temporary exemption . . .
3. The granting of the petition is in accord with the purposes of the Act and is in the public interest

A special public interest exemption was proposed by ERA to reflect the temporary surplus of natural gas caused by deregulation [78]. This special exemption is proposed to become Part 508 of Subchapter E, Chapter II, Title 10 of the Code of Federal Regulations. The new regulation would serve to inform the utility industry that temporary public interest exemptions will be granted to allow the use of natural gas above the level stipulated in the FUA. Section 301(a) of the FUA prohibits a facility from using natural gas unless it was used as a primary energy source in 1977, and in no greater proportion than the average quantities used in the base years 1974-76. ERA states that the use of natural gas is more in the public interest and consistent with FUA than the use of middle distillate fuel oil. A facility would be granted an exemption to burn gas if it met the following criteria:

a. your existing powerplant would be (without this exemption):
   1. prohibited on May 8, 1979 from using natural gas . . .
   2. prohibited from using natural gas in excess of the average base year quantities . . .
b. your proposed use of natural gas as a primary energy source, to the extent that such natural gas use would be prohibited by Sec. 301(a)(2) or (3) of the Act, will displace middle distillate in section 508.4 of this Part; and
c. you must show that such use of natural gas would not displace coal or another alternative fuel.

In general, the requirements for permanent exemptions are more rigid than for temporary exemptions. For both a mandatory and discretionary permanent exemption consideration must be given to the potential use of fuel mixtures under Sec. 504.15 of the proposed regulations, and the use of fluidized bed combustion under 504.16. If ERA determines on a generic basis that fluidized bed combustion is technically and economically feasible, applicants for exemptions must demonstrate that this technique is not applicable to their installation.

A mandatory exemption for lack of alternate fuel supply is described in Sec. 504.31 of the proposed regulations. Applicants must demonstrate to the satisfaction of ERA that:

1. You made a good faith effort to obtain an adequate and reliable supply of an alternate fuel of the quality necessary to conform to design and operational requirements of the existing powerplant;

and;

2. The cost of using such a supply would substantially exceed the cost of using imported petroleum during the remaining useful life of the existing powerplant as defined in Sec. 504.12 (Cost Calculations) of these regulations.

The cost calculation previously described plays an important role in determining whether this exemption will be granted.

Section 504.32 of the regulations allows a permanent mandatory exemption for site limitations similar to those discussed in the section describing temporary exemptions, but for limitations which "cannot be reasonably expected to be overcome within five years after effective date of the prohibition." The section describing this exemption details the burden of proof placed on the utility to achieve this exemption. Section 504.33 provides for a mandatory permanent exemption due to environmental requirements, but again it must be documented that, "you cannot burn alternate fuels without violating applicable environmental requirements within five years after the effective date of the prohibition."

The use of a fuel mixture is grounds for a mandatory permanent exemption under Sec. 504.36 if the following three points are demonstrated to the satisfaction of ERA:

1. You propose to use a mixture of natural gas or petroleum and an alternate fuel as a primary energy source;
2. You are not capable of complying with the applicable prohibitions; and
3. The amount of petroleum or natural gas you propose to use in the mixture will not exceed the minimum percentage of the total Btu

heat input needed to maintain operational reliability consistent with maintaining a reasonable level of fuel efficiency.

A permanent mandatory exemption for use of a facility for emergency purposes only is detailed in Sec. 504.37. An emergency situation is defined as, "when the operating utility has been required to curtail its industrial customers by 10% or more from expected non-interruptible demand." In order to receive this exemption it must be demonstrated to ERA that the prohibition cannot be complied with.

A permanent mandatory exemption will be granted under Sec. 504.38 for a peakload powerplant if the following three points are demonstrated to ERA:

1. The powerplant will be operated solely as a peakload powerplant for the remaining life of the powerplant;
2. You are not capable of complying with the applicable prohibitions ...
3. Modifications of the powerplant to permit compliance with the prohibitions of the Act--
   A. Is technically infeasible; or
   B. Would result in an unreasonable expense as described in the cost calculation portion of these regulations.

The exemptions for powerplants of under 250 MMBtu/hr (nominally 25MW) is applicable only to natural gas usage, and therefore is not significant for this study. The use of LNG is grounds for a permanent mandatory exemption if the following three points are satisfied;

1. The Administrator of the EPA or the appropriate State air pollution control agency has certified that the use of coal or any available coal derived fuel as a primary energy source will cause

or contribute to a concentration, in an air quality region or any area within such region, of a pollutant for which any national ambient air quality standard is or would be exceeded;

2. (non-air environmental constraints)
3. The LNG to be used at your power plant will be produced in a foreign country.

Applications for discretionary permanent exemptions must demonstrate the infeasibility of utilizing mixtures as specified in Sec. 504.15, and the infeasibility of using fluidized bed combustion as specified in Sec. 504.16. In addition, to qualify for exemptions A or C it must be demonstrated that no alternative supply of power is available. To satisfy this preliminary requirement for these two exemptions, under Sec. 504.13 it must be demonstrated to the satisfaction of ERA that:

1. You cannot purchase electricity from another utility at a cost which does not substantially exceed the cost of your existing plant using imported petroleum . . .
2. You cannot construct and operate an alternate fuel fired plant either within or outside your service at a cost which does not substantially exceed the cost of imported petroleum. See Sec. 504.12 (cost calculation) . . .
3. (combination of the above two possibilities) . . . ERA will consider any combination of purchased electricity and alternate fuel fired plant that costs less than 1.5 times the cost of your existing plant using imported petroleum to be at a reasonable cost. . .
4. You cannot meet load requirements with existing facilities,

employing system conservation measures, assisting end use customers to conserve electricity, and implementing load management techniques.

A discretionary permanent exemption can be applied for due to state or local requirements under Sec. 504.34. To receive this exemption four points must be demonstrated to ERA:

1. With respect to the site of the power plant, the operation of the existing power plant using an alternate fuel is infeasible because of a state or local requirement;
2. If such state or local requirement is under a building code or nuisance or zoning law, no other exemption under Title III, Subtitle B of the Act could be granted;
3. You have, in good faith, attempted unsuccessfully to obtain a waiver or variance from the state or local requirement . . .
4. The granting of the exemption would be in the public interest and would be consistent with the purposes of this Act.

A permanent discretionary exemption for the use of cogeneration can be provided under Sec. 504.35. Two minimum criteria must be demonstrated to ERA to receive this exemption:

1. You are unable to comply with the applicable prohibitions; and
2. There are economic and other benefits of cogeneration with petroleum or natural gas, which are unobtainable through the use of an alternate fuel.

An intermediate load power plant can apply for a discretionary permanent exemption under Sec. 504.39. To receive this exemption the following points must be demonstrated to the satisfaction of ERA:

1. The Administrator of the EPA or the Director of the appropriate state air pollution control agency has certified that the use of any available alternate fuel as a primary energy source will cause or contribute to a concentration . . . of a pollutant for which any national ambient air quality standard is or would be exceeded . . .
2. The intermediate load power plant will replace no more than the equivalent generating capacity of existing units which:
   - i. Permanently cease operation within one month of ERA's granting the intermediate load power plant this exemption;
   - ii. Use natural gas or petroleum as a primary energy source;
   - iii. Are owned by the same person who is to operate the existing power plant;
   - iv. Are capable of using coal as a primary energy source; and
   - v. Would cause or contribute to a pollutant concentration in a manner described in paragraph (1 above) . . .;
3. The power plant is and shall continue to be operated only as an intermediate load power plant in which the electrical generation, in kilowatt hours, for any 12-calendar-month period, shall not exceed the power plant's design capacity multiplied by 3,500 hours;
4. The net heat input rate for the power plant will be maintained at or less than 9,500 Btu's per kilowatt hour throughout the useful life of the power plant;
5. The power plant has the capability to use a synthetic fuel derived from an alternate fuel as a primary energy source.

The FUA classifies all power plants which began construction or acquisition after April 20, 1977, as "new". The FUA authorizes ERA to draft regulations which classify certain installations for which construction or acquisition began between April 20, 1977, and November 9, 1978, (enactment date of FUA) as "existing facilities", and therefore subject to the less stringent standards. Regulations drafted for this purpose appeared in the November 22, 1978, issue of the Federal Register [79]. These proposed regulations define "substantial construction" for a power plant with a field erected boiler as the date on which the unit became operational. Since field erection is generally a necessity for power plant installations due to the large size, the acquisition clause is not relevent and consequently if between the previously mentioned dates the unit became operational it is classified as a "transitional" facility. Transitional facilities may petition ERA for an "existing facility" classification if it can be demonstrated that a "new" classification, "would result in a substantial financial penalty for an installation or power plant, or would result in a significant operational detriment to an installation or in an impairment of the electric system reliability for a power plant.".

Penalty provisions for violation of FUA are provided in Title VII, Subtitle C of FUA, and these penalties were incorporated into the regulations proposed by ERA on November 17, 1978 [80]. These penalties are to be incorporated into Part 501 of 10 CFR, Chapter II, Subchapter E and public hearings were held on the proposed regulations on Feb. 7, 1979 in Boston. Regulations dealing with FUA have not yet been promulgated as of May 15, 1979. Penalties in the FUA and the regulations provide for a fine of not more than $50,000 or imprisonment of not more than 1 year, or both, for each day of a willful violation of FUA. If petroleum or natural gas usage exceeds the level allowed by an exemption granted by ERA the penalty will not exceed $3/Mcf of natural gas or $10/barrel of oil. With respect to corporate personnel the act states, "If you are a director, officer, or agent of a corporation and you willfully authorize, order or perform any act or practice constituting a violation of any provision of the regulations issued under authority of the Act, or any rule, or exemption, or permit issued pursuant thereto, you will be subject to the penalties specified in . . . (above)."

Power plants which have received prohibition orders under Sec. 2(a) of ESECA, which regulates existing facilities, may elect under Sec. 762 of FUA to be covered under Title III of FUA through a petition to ERA. This option is not open to facilities which have received a Notice of Effectiveness under ESECA (none as of May 15, 1979, but probably Brayton Point in the near future). Plants for which prohibition orders under ESECA are pending, final, or which on review were held unlawful and set aside on the merits are not covered by the provisions of FUA (this should be applicable to Mt. Tom and Brayton Point but not to Middletown, Norwalk Harbor, and Schiller as prohibition orders for these facilities have been withdrawn).

Brayton Point units 1, 2, and 3 received a prohibition order under the authority of ESECA on June 30, 1977 [81]. The prohibition order was preceded by a notice "Intention to Issue Prohibition Orders to Certain Powerplants" (42 FR 21950), and states in the first paragraph:

> Pursuant to Section 2 of the Energy Supply and Environmental Coordination Act of 1974 (ESECA), 15 USC Sec. 792 (Supp. V, 1975) as implemented by Chapter II, Title 10 of the Code of Federal Regu-

lations (CFR), Parts 303 and 305, the Federal Energy Administration (FEA) hereby orders that the above listed powerplants shall be prohibited from burning natural gas or petroleum products as their primary energy source. Such prohibition shall become effective on the date stated in a Notice of Effectiveness to be served on the powerplants, pursuant to 10 CFR 303.37(b) and 305.7, subsequent to issuance of this Prohibition Order.

The 51 page prohibition order describes the subsequent procedures which must occur before the Notice of Effectiveness is issued, and support documentation is provided to support the following findings:

1. On June 22, 1974, each powerplant had the capability and necessary plant equipment to burn coal;
2. The burning of coal by each powerplant, in lieu of petroleum products or natural gas, is practicable and consistent with the purposes of ESECA;
3. Coal and coal transportation facilities will be available during the period this Prohibition Order will be in effect; and
4. The prohibition of the powerplants from burning natural gas or petroleum products as their primary energy source will not impair the reliability of service in the area served by such powerplants.

Under the terms of ESECA the issuance of a Notice of Effectiveness must be preceded by the certification of the EPA Administrator of the earliest date by which conversion can occur and satisfy the applicable air pollution requirements. In addition, the DOE must finalize an Environmental Impact Statement before final proceedings.

To support their findings in the Prohibition Order the FEA referred to

FEA sponsored study conducted by PEDCo, data from New England Power Co., and data from other federal agencies. It is concluded that a net annual increase in cost for converting Brayton Point 1, 2 and 3 will occur of $6,030,000, and that this cost translates to 56¢/barrel of oil saved, or .35 mil/kWhr rate increase to the utility customers. This cost was considered reasonable by the FEA. Compliance with air pollution regulations was to be achieved through the use of .7%S coal and the addition of ESP capacity.

Two months prior to the issuance of the Brayton Point Prohibition Order an agreement was reached by the Federal Regional Council of New England to coordinate a dialogue with involved parties. The agreement is entitled, "Voluntary Conversion to Coal at the Brayton Point Power Plant", [82]. The project was funded with $5,000 each from the Federal Energy Administration, the EPA, New England Power, and the Bureau of Mines. In addition to the groups mentioned, the Mass. Dept. of Environmental Quality Engineering and Mass. Energy Policy Office participated, with the program coordination performed by the Center for Energy Policy, Inc. The agreements reached during these meetings were instrumental in the drafting of "Memorandum of Understanding between The Commonwealth of Massachusetts and New England Power Co." The agreements reached by the workgroup parallel those agreed to in the Memorandum of Understanding [83]:

1. New limits for emissions of sulfur dioxide and particulates will be set for this facility to make conversion to coal economic and environmentally acceptable.
2. The DEQE will promulgate a new regulation for this purpose.
3. These emission limits will not be revised for at least ten years unless required by changes in law or new scientific information regarding the impact of emissions from coal combustion on human

health.

4. The sulfur emission limit for the coal burning units will be raised from 0.55 lbs/MMBtu to 1.21 lbs/MMBtu, the equivalent of 2.2% sulfur oil now being burned at the station.
5. Coal sulfur content will not exceed 1.21 lbs/MMBtu on a monthly average and not exceed 2.31 lbs/MMBtu during any 24 hour period.
6. The particulate emission limit for the coal burning units will be lowered from 0.12 lbs/MMBtu to 0.08 lbs/MMBtu.
7. Additional electrostatic precipitator capacity will be added and designed to achieve particulate emissions of 0.06 lbs/MMBtu when burning "design" coal (1%S, 8% ash, 13,000 Btu/lb).
8. If, as expected, there are no significant adverse environmental impacts with these limits. the limits will be retained for the remaining life of these units, subject to changes in controlling legislation.
9. Adequate and approved methods for disposal or commercial reuse of ash generated and collected while burning coal will be available at all times.
10. Certain of these agreements will be set forth in a Memorandum of Understanding between New England Power Co. and the Dept. of Environmental Quality Engineering.
11. Mediation will be considered as a means to resolve future disputes over conversion to coal at Brayton Point.

Despite the voluntary nature of the Brayton Point coal conversion the provisions of ESECA assist New England Electric in negotiating with the environmental authorities and escaping the modification clause of the Clean Air

Act which could otherwise classify the facility as subject to NSPS. Massachusetts regulation 310 CMR 7.17 was adopted August 7, 1978, entitled, "7.17 SE Coal Conversion -- Brayton Point Station, New England Power Co." This regulation incorporates the conditions of the discussed agreement. In a May, 1978, DEQE public information document concerning the proposed regulation it is pointed out that in contrast to the provisions of the FEA prohibition order, it is expected that the proposed agreement will save New England Electric customers $10,000,000 per year rather than cost them $6,030,000, the figure already cited from the FEA order (New England Electric claims the cost under the FEA plan would be even greater) [84]. The document states that with respect to air quality impacts, no violations of sulfur dioxide ambient air quality standards will occur and that due to the particulate emission limit, "Brayton Point Station will not cause or significantly contribute to ambient air quality standard violations for total suspended particulate matter". This statement is made from a background of numerous TSP violations having been recorded in the Fall River area directly east of the plant by monitors sponsored by NEPCO and operated by Environmental Research and Technology (ERT). The EPA Surveillance and Analysis Division (S&A) analyzed NAAQS violations at the Plymouth St., North Main St., and Milliken Blvd. sites [85]. In their August 31, 1977, report some of the S&A's conclusions were:

> 5. Major fuel burning sources at the Brayton Point and Somerset Facility did not contribute significantly to the NAAQS exceedances which were studied.

7. The most probable cause for the secondary TSP violations at the Plymouth site are street sanding and cleaning operations.
8. The most probable causes for the secondary TSP violations at the North Main St. site are the construction activities related to Rt. 79 in the vicinity of the site, road dust re-entrainment, a brush fire on June 10, 1976, and elevated regional sulfate levels.

These conclusions are discussed in greater detail in the following section which examines secondary source influences on ambient air quality.

Final federal approval for incorporation of the Mass. regulation governing coal conversion at Brayton Point into the Mass. SIP was announced in the May 21, 1979, issue of the Federal Register [86]. Progress is also underway on the preparation of a final Environmental Impact Statement (EIS) for the conversion. The availability of a draft EIS and the slating of public hearings for November 14 and 16, 1978, was announced in the October 13, 1978, issue of the Federal Register [87]. DOE officials were contacted and they stated that the final EIS will be issued in June, 1979 [88]. Upon the release of the final EIS the DOE will be able to issue a Notice of Effectiveness for the Brayton Point conversion. Plans presently call for unit 1 to convert in 1982, unit 2 in 1983, and possibly unit 3 thereafter.

Prohibition orders under ESECA were issued to both the Mt. Tom and Middletown plants of Northeast Utilities. The order for Mt. Tom is still pending, while the order for Middletown has been dropped due to opposition from the State of Connecticut [89]. Consequently, Mt. Tom for the time being will not be affected by FUA unless this change is requested by the utility, and Middletown could become subject to an order under FUA at the discretion of ERA. Boston Edison's Mystic 7 unit is not subject to action under FUA due to the superheater design making the unit adaptable only to oil firing. The New Boston units of Boston Edison on the other hand were originally designed with dual firing in mind and consequently with the addition of necessary equipment could burn coal. The cost test previously discussed will primarily determine whether these units could be subject to action under FUA [90].

C. Ambient Air Quality

1. Ambient air quality in MA and CT

The influence of powerplants on ambient particulate levels is typically harder to quantify than the influence on sulfur dioxide levels. The ease of SO_2 source identification arises from the relatively small number of significant SO_2 sources. Of the 32,824,000 tons of SO_2 emitted to the atmosphere in the United States for 1975, 25,438,000 tons was the result of fuel combustion and of that amount 20,481,000 tons emanated from electric generation along [91]. The effect of secondary particulate sources has been the subject of significant research in the last few years [15,92]. These secondary particulates will be partly atmospherically generated sulfate in the respirable size range and the result of transportation and construction in the large particle size range. Areas can be impacted by specific secondary sources such as the particulate level increases observed in Wisconsin during planting season [93]. But even for particulate sources which are permitted or registered (in the case of particulates emanating from the tailpipes of vehicles), a relatively disaggregated picture of sources for particulate emerges. Of the 13,767,000 tons of particulate emitted from registered sources in 1975, 5,548,000 tons were caused by fuel combustion and 3,069,000 from electric generation in particular [91]. Consequently, government documents show that 22% of particulate emissions compared to 62% of sulfur oxide emissions emanate from electric power stations. The actual discrepancy is even greater, since particulate sources not counted by the government play a more important role than sulfur oxide sources not counted. Note that registered particulate emissions are just 42% of sulfur oxide emissions by weight, demonstrating the potential impact of atmospheric transformations of sulfur oxide to sulfate particulate on ambient levels.

Most powerplants, even coal fired units, emit an order of magnitude more sulfur oxides than particulate. This ratio will persist despite adoption of the "full-scrubbing" NSPS option (see section on New Source Performance Standards, actual ratio of allowed SO_2 to particulate emission would vary from 6.7 to 40). Ambient air quality standards for sulfur oxides are set just slightly higher than those for particulate (see Table 1.1). Yet controversy surrounds the impact of power plants on both of these pollutants. This is perhaps due to the fact that health effects are ascribed primarily to the simultaneous presence of these two materials (see section on National Ambient Air Quality Standards). In addition, high background levels of particulate can generate concern that the smaller incremental impact of a powerplant on ambient particulate levels can cause a violation of the TSP standard. Meteorologists believe that sulfur oxides and particulates obey the same laws for dispersion from powerplant smokestacks [94].

Ambient air quality in Massachusetts and Connecticut is more favorable with respect to sulfur dioxide than particulates. While both states are entirely in compliance with NAAQS for sulfur dioxide, all of Connecticut and patches of Massachusetts are not in compliance with NAAQS for particulates [95]. Sites showing violations of the TSP NAAQS in MA and CT are listed in the section on state implementation plans. Ambient particulate levels in the New England area are typically somewhat higher than sulfur dioxide levels, despite the higher level (all weight per cubic meter basis) of sulfur dioxide standard [96]. This was not always the case. Connecticut records show that 45% of sampling sites were in violation of annual SO_2 primary standards in 1971, with an additional 37% in violation of secondary standards [97]. This is in deference to just 31% of TSP sampling sites showing violations of the primary annual standard in 1971. The regional EPA Adminstrator for New England stated with respect to the program for controlling air pollution, "the most significant accomplishment is the control of sulfur oxides in the atmosphere." [98]. Despite the switch from coal to oil combustion in the New England area during the early '70s, and the consequent reduction in particulate emissions, ambient particulate levels have remained a problem. This lack of response points to the influence of secondary unpermitted sources on ambient levels.

A complication which must be introduced is the variability of particulate matter with respect to size and toxicity. Techniques currently utilized to test for compliance with TSP standards determine total particulate mass only. Future standards could conceivably be more discriminatory. Consequently, it is important to judge the impact of a powerplant not only on the total ground level TSP concentration, but also on the nature of that concentration with respect to size and toxicity. The legal mechanisms have already been described which will probably bring about a fine particle standard within the next several years. Standards based on particulate toxicity would result from scientific data which documented a threat to public health. This subchapter IC investigates the impact of powerplants on ground level particulate concentration and character. This investigation should help in judging the probability of enhanced environmental constraints on power stations in the future.

A unique opportunity for the study of a powerplant's impact is provided by the conversion of the Brayton Point facility of New England Electric to coal. The Massachusetts Technology Development Corporation study previously introduced picked Fall River, Kenmore Square, and Springfield for study. The Fall River area is directly impacted by the Brayton Point facility, a facility included in the technical part of this study. The Kenmore Square site is difficult to analyze because it is generally upwind of the Boston Edison plants and is affected by a multitude of major sources. This analysis of the Fall River situation yields conclusions which should be applicable to the general ambient TSP problem. Fall River is currently designated as nonattainment of the TSP secondary standard, despite the fact that Massachusetts monitors have not recorded a violation of the secondary standard in several years [95]. Two state sampling sites are operated in the Fall River area. TSP measurements recorded at these sites are reported in Table 1.11 [31].

Violations of TSP standards were detected by monitors of the "Brayton Point Monitoring Network", a network established by New England Power Co. in 1974 as a condition to temporarily burn coal. The company continued to operate these monitors after the plant switched back to oil in 1975. Violations recorded by this network and the ambient wind conditions at the time of violation are shown in Table 1.12 [99]. The positions of the two power-

TABLE 1.12

High Particulate Concentrations Measured

Date	Day	Site	Wind Vector* °/mph	Concentration (ug/m^3)
12/5/76	Sunday	Plymouth Avenue	290°/5	422
6/11/76	Friday	North Main Street	240°/12	175
4/9/76	Friday	North Main Street	30°/13	213
4/15/76	Thursday	Plymouth Avenue	230°/8	153
2/9/76	Monday	Plymouth Avenue	340°/5	468
2/12/76	Thursday	Plymouth Avenue	280°/10	173
2/21/76	Saturday	North Main Street	210°/7	150
5/15/75	Saturday	North Main Street	180°/8	185
5/21/75	Wednesday	North Main Street	150°/3	156
4/3/75	Thursday	North Main Street	160°/5	160
4/12/75	Saturday	Plymouth Avenue	300°/7	191
4/18/75	Friday	North Main Street	170°/8	177
3/7/75	Friday	Milliken Boulevard	170°/6	188
3/16/75	Sunday	Milliken Boulevard	230°/5	159
3/19/75	Wednesday	Milliken Boulevard	140°/12	189
2/20/75	Thursday	Milliken Boulevard	280°/8	455
1/24/75	Friday	Milliken Boulevard	220°/8	166

*From T. F. Green Airport, Warwick, RI

TABLE 1.11

TSP measurements by Massachusetts DEQE in the Fall River area for 1976 and 1977 in $\mu g/m^3$

	Central Fire Station		Globe Street Trailer	
	1976	1977	1976	1977
Number of observations	55	58	47	7
Annual Geom. mean	48	55	N/A	N/A
Geometric Std. Dev.	1.44	1.44	1.45	1.67
Max. 24 hr. observ.	99	147	136	112
2nd Max. 24 hr. observ.	90	126	110	68
No. of observ. above 260	0	0	0	0
No. of observ. above 150	0	0	0	0

plants in the area, Brayton Point and Somerset Station (Montaup Electric Co.), are shown in Figure 1.4 along with the positions of the state and ERT monitoring sites [100]. The Milliken Boulevard Site was only operated for a few months up till early 1975. The EPA Regional Office had this site relocated to the Plymouth Avenue fire station for the following reasons [101]:

1. Computer modeling did not predict any impact of Brayton Point at this location.
2. There was no population exposure at the site
3. The fire station was determined to be a better center city site
4. Re-entrainment of particulates would cause elevated TSP levels

The N. Main St. site is 2.8 miles from Brayton Point and would be directly impacted by a wind coming from 250°. The Plymouth Street site is 2.4 miles from the plant and is affected by a wind coming from 312°, the Milliken St. site is 1.8 miles from the plant and is downwind from a wind

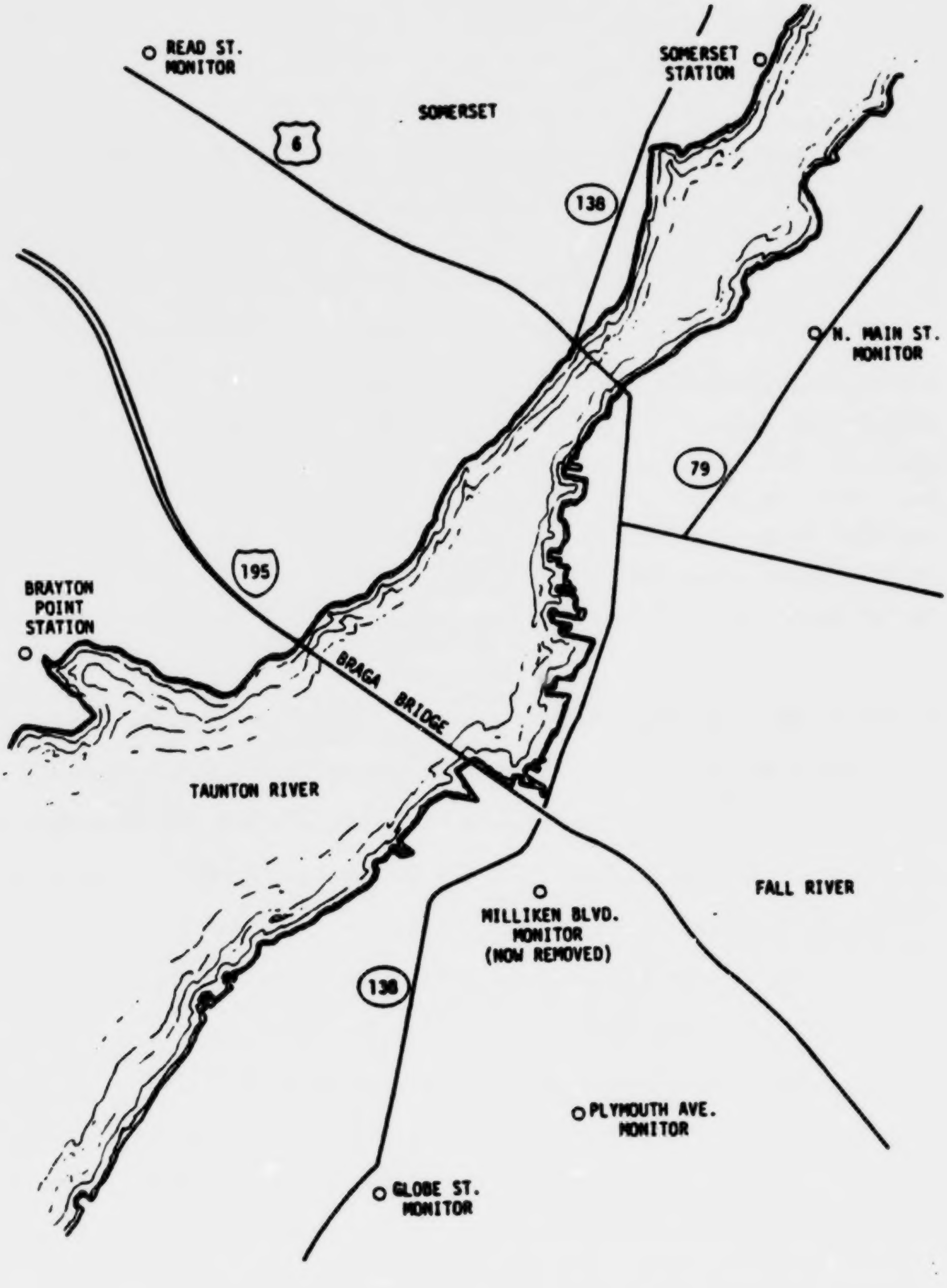

READ ST.
MONITOR
SOMERSET
STATION
SOMERSET
6
138
N. MAIN ST.
MONITOR
79
195
BRAYTON
POINT
STATION
BRAGA BRIDGE
TAUNTON RIVER
FALL RIVER
MILLIKEN BLVD.
MONITOR
(NOW REMOVED)
138
PLYMOUTH AVE.
MONITOR
GLOBE ST.
MONITOR

Figure 1. 4 Air Monitoring Stations for the Brayton Point Power Plant.

vector of 295°. Normal surface wind direction is reported to vary from originating in the northwest in January to the southwest in July for Southeastern MA, indicating the likelihood of the powerplants having an ambient impact at each of these sites [102]. Wind direction is not the sole indicator of plume impact, as the area of high pollutant concentration may pass entirely over a sampling site.

In response to a 1977 request of the MA DEQE under Ch. 494 to raise the allowed sulfur limit of the Brayton Point facility from 0.55 lb/MMBtu to 1.21 lb/MMBtu the EPA Region 1 Surveillance and Analysis Division (S&A) conducted an evaluation of the exceedances reported by the "Brayton Point Network". This study was completed in August of 1977, and, "after careful study of the filters on which pollutants had been deposited, the Agency found no substantial contribution from the powerplant" [103]. Approval to burn the higher sulfur fuel was granted to the Brayton Point plant on January 12, 1978. The results of the S&A study will be discussed in more detail in section IC3.

The Massachusetts Technology Development Corporation (MTDC) study enlarges on the analysis done by the EPA S&A group by gathering new data to document the influence of secondary sources. This study was introduced in the section of this report which discusses MA and CT SIPs. In the introduction to a monthly progress report on the work, the purpose of the MTDC study is stated [104]:

> The purpose of this study is to determine the causes of TSP violations at three specific sites in the Commonwealth of Massachusetts. To date it has been assumed that these sites are subject to considerable influence by particulate emissions such as re-entrained sand

> and surface dust. The study is an attempt to define the types, quantities, and sources of particulate matter contributing to elevated TSP levels at such sites in order to develop effective control strategies to attain and maintain . . . Ambient Air Quality Standards.

GCA Corp. was awarded a contract to conduct the study for MTDC on October 17, 1977. The sampling conducted for this program commenced January 1, 1978 and ran for a period of one year. Researchers at GCA Corp. have prepared a paper which discusses the results of the study for presentation at the June 1979 meeting of the Air Pollution Control Assn. [105]. The introduction to the paper summarizes the sampling techniques utilized:

> The program consisted of a one-year observation period during which particulates were measured intensively at three sites in Massachusetts using a number of sophisiticated measurement techniques to complement the routine operation of hi-vols. The sites selected for study were Kenmore Square in Boston, the area adjacent to I-91 between E. Columbus Avenue and Court St. in Springfield, and the area on either side of Plymouth Avenue along Manton and Niagara Streets in Fall River. Inclusion of the first two of these sites was based on a continuing history of violations, while the Fall River site offered an opportunity to investigate more thoroughly the relative contribution of sources in an area that is frequently downwind from a major power plant. At the time these sites were selected, each was suspected of being significantly influenced by nearby motor vehicle activity (re-entrainment of road sand and dust), but only limited documentation was available to

support this hypothesis.

Resolution of the relative importance of various particulate sources was approached through chemical and elemental analysis of selected filters, and by defining the three-dimensional particulate field near two of these sites (including Fall River). Additionally, particulate concentrations and traffic data were examined for possible source-receptor relationships. Special particulate instrumentation included dichotomous samplers to separate respirable and nonrespirable components on a 24-hour basis (cut points of 3μm and 20μm), and continuous monitors to provide hourly concentrations of respirable and total particulates (cut point at 3.5 μm).

The MTDC study was designed to provide data to support the movement of monitors away from roadways to bring Massachusetts into compliance with the NAAQS. The results of this study will be discussed in section IC3.

Bob Donovan, Chief of Air Quality Control for the Southeastern Massachusetts Interstate Air Quality Control Region (AQCR 120 which includes Fall River) was contacted for information on the nonattainment status of Fall River for TSP [106]. He was hopeful that the final report of the MTDC study would persuade the EPA to change the status to attainment. Mr. Donovan pointed out that state monitors have not seen any violations of the TSP standard in Fall River. The impact of the power plants on ambient air quality in Fall River, according to Mr. Donovan, was accurately predicted by a study of this question performed in November, 1976, by ERT (these results are utilized in the subsequent section on powerplant impact). Mr. Donovan was concerned but unsure of the impact of long-range sulfate transport on ambient particulate levels.

2. Effect of utilities on ambient particulate levels

Two general approaches can be adopted with respect to calculating the ground level impact of powerplants. The less sophisticated approach entails comparing the emissions from powerplant stacks to the total area permitted emissions. This data was reviewed in the last section for emissions nationwide. It is also possible utilizing the NEDS (National Emissions Data System) to compare the emissions from the two powerplants in the Fall River area to the total registered emissions in the Southeastern Massachusetts Air Quality Control Region [107]. In addition to the Brayton Point and Somerset Station facilities, the Southeastern Massachusetts district includes the Taunton Municipal Lighting Plant in Taunton and the Canal Electric Co. in Sandwich. Of the 12,935 tons/year of particulate emissions accounted for by this accounting system, 2,445 tons/year (19%) are the result of electric power generation, 1,050 tons/year are attributed to the Brayton Point facility, and 463 tons/year are accounted for by the Somerset facility. Consequently 8% of the regional emissions were attributed to the Brayton Point facility in 1975, with the actual percentage somewhat less due to the influence of secondary sources and long-range transport of fine particulate.

Regional accounting was utilized by the Department of Energy to predict compliance with annual NAAQS in the face of increased energy utilization by 1985 [18]. The health and welfare based NAAQS consist not only of annual, but also of short term, time averaged standards. Both particulates and SO_2 are regulated by a 24 hour standard, and SO_2 alone is regulated by a 3 hour standard. In the case of particulates the 24 hour standard has typically been more restrictive than the annual standard. Regional accounting is not accepted as a valid technique for predicting compliance with 24 hour air quality standards. The impact of a facility on compliance must be predicted through the use of atmospheric dispersion techniques which utilize local meteorological and terrain data. The primary 24 hour TSP standard is 260 $\mu g/m^3$ abd the secondary standard is 150 $\mu g/m^3$, both of which are not to be exceeded more than once per year to register compliance.

Two studies are available which help to assess the impact of Brayton Point on ambient particulate concentrations in Fall River. The first study conducted by ERT utilized SO_2 measurements gathered at seven sites between June 1, 1974, and May 31, 1975, to predict the effect on local air quality of increasing the allowed sulfur content in fuel for the Brayton Point and Somerset electric generating stations [108]. Due to the similarity of dispersion for particulates and SO_2, substitution of particulate source strength for SO_2 can yield ground level impacts not only for total particulates but also for fine particulates in particular.

The second study, conducted by Walden Division of Abcor, Inc., as part of the drafting of an environmental impact statement is designed to predict the ground level ambient particulate impact of the conversion of Brayton Point units 1, 2, and 3 to coal [109]. This analysis compares the plant impact to ground level background concentrations for SO_2 and particulates using plant emission data from previous tests and the proposed permit levels. The methodology utilized by Walden yielded a lower ground level impact than that predicted by ERT. Mr. Kiotsa, meteorologist at Walden explained this result through his use of a looping plume methodology to predict a 24 hour maximum ground level concentration [110]. Turner, author of the widely used EPA "Workbook of Atmospheric Dispersion Estimates" explained this result in a recent review article [111], "under unstable conditions the instantaneous plume alternately is released into large updrafts and regions of downdrafts, causing parts of the plume to occasionally reach ground level close to the stack. Because of the appearance of the instantaneous plume to be in large loops, this condition is called looping. . However, depending upon the degree of wind direction persistence, the neutral plumes may continually impact the same vicinity for a number of hours and cause higher 24-hour concentrations." Consequently, the methodology utilized by Walden is appropriate for estimating the maximum 3 hour concentration, but not the maximum 24 hour concentration.

The ERT study utilized the Gaussian plume model to predict ground level impacts of point sources. This model predicts that plume material moves downwind with the wind speed (dispersion in the direction of travel is ignored). Turbulent diffusion is the mechanism assumed to account for travel in the two dimensions perpendicular to the direction of wind driven transport. The resulting concentration distribution is a two-dimensional Gaussian with separate dispersion coefficients modeling transport in the vertical and horizontal directions. Transport is highly dependent on the degree of atmospheric stability, which can be determined from the vertical temperature distribution, or lapse rate and wind speed. Pollutant material is modeled as reflecting off of the ground, and vertical mixing is limited to a region extending up to a mixing depth. The mixing depth is determined by the atmospheric temperature distribution measured by radiosonde observations conducted in Chatham, MA. Hourly meteorological surface data was taken for the ERT study from Green Airport in Warwick, Rhode Island. The basic Gaussian equation utilized in the ERT study is shown as Eq. 1.2.

$$\chi(0,0,Z) = \frac{Q(x,\ -y,\ H)}{2\pi\ \sigma_y\ \sigma_z\ u}\ \exp\left[\frac{-1}{2}\left(\frac{y}{\sigma_y}\right)^2\right] \cdot \tag{1.2}$$

$$\left[\exp\left[\frac{-1}{2}\left(\frac{Z-H}{\sigma_z}\right)^2\right] + \exp\left[\frac{-1}{2}\left(\frac{Z+H}{\sigma_z}\right)^2\right]\right]$$

$x \equiv$ upwind dimension

$y \equiv$ crosswind dimension

$Z \equiv$ vertical dimension

$H \equiv$ height of stack plus plume rise

$Q \equiv$ source strength (mass/time)

$\sigma_y(x), \sigma_z(x) \equiv$ crosswind and vertical dispersion coefficients, functions of X and meteorological conditions

$u \equiv$ average wind speed

$\chi \equiv$ ground level pollutant concentration (mass/volume)

Ground level particulate impacts can be calculated by multiplying the resulting SO_2 ground level concentration by the ratio of particulate to SO_2 source strengths. The ERT model was verified against one year of observed ground level concentrations, plant operating data, and meteorological data. Subsequently the model was run against meteorological data gathered from 1970 to 1974 assuming that both the Brayton Point and Somerset facilities were carrying full load and burning 2.2%S fuel. Ground level concentrations were predicted on an hourly basis for a network of 128 receptor locations arranged in concentric circles around the two power plant facilities. Longer time averages were computed from the series of one hour predictions. The conversion to the higher sulfur content fuel would not be permitted if the summation of background and power plant ground level concentrations led to a violation of the NAAQS for any of the 128 receptor sites.

The modeling study predicted no violations of the SO_2 3-hour or annual standard with the conversion to the higher sulfur content fuel. The 24 hour standard proved to be the most restrictive, with the study finding a greater ground level impact from the Somerset facility than from the larger Brayton Point facility. This larger impact is the result of the lower stack heights, and the study concludes that no violations of the SO_2 standards will occur if Somerset Station is restricted on higher sulfur fuel to 75% of full load. This load limitation was recently incorporated into the Massachusetts SIP by the EPA in a revision which permits both facilities to burn 2.2% oil [112].

To judge the impact of a power plant on ambient total and fine particulate it seems prudent to consider just the points of maximum impact predicted in the SO_2 study. Exceedances of the .14 ppm, 24-hour SO_2 standard are listed in Tables 1.13, 1.14, and 1.15 [113]. The data is divided between exceedances caused primarily by the impact of the Brayton Point plume, the impact of the Somerset Station plume, and from instances in which the wind lined up the two facilities and both contributed. The hour count used in the study is defined as beginning January 1, 1970, and each receptor number designates a particular position in the Fall River area specified in the report [114]. Note that two violations must be recorded in one year for any one receptor to constitute a violation. Two violations are shown in Table 1.14 for receptors 92 and 93. These violations would not be predicted if the Somerset facility is restricted in load by as little as 11%.

Tables 1.16 and 1.17 taken from the ERT study show the full-load SO_2 emissions for the Brayton Point and Somerset stations [115]. Note that boilers 2, 3, 4, and 5 of the Somerset Station are generally not in opera-

TABLE 1.13

BRAYTON POINT CASES

24-HOUR AVERAGE PREDICTED SO_2 CONCENTRATIONS GREATER THAN 0.14 ppm

Year	Hour Ending	Receptor	Total Concentration (ppm)	Brayton Point Contribution (ppm)	Somerset Contribution (ppm)	Background Contribution (ppm)	2nd Largest Concentration for the Year (ppm)
1971	10272	29	0.159	0.144	0.0	0.015	< 0.100
1971	10272	2	0.146	0.137	0.00	0.009	< 0.100

TABLE 1.14

SOMERSET CASES

24-HOUR AVERAGE PREDICTED SO_2 CONCENTRATIONS GREATER THAN 0.14 ppm

Year	Hour Ending	Receptor	Total Contribution (ppm)	Brayton Point Contribution (ppm)	Somerset Contribution (ppm)	Background Contribution (ppm)
1970	1656	93	0.147	0.0	0.138	0.009
1970	8160	95	0.155	0.0	0.152	0.004
1971	10152	92	0.151	0.026	0.119	0.006
1971	10272	93	0.197	0.0	0.191	0.006
1971	10344	92	0.145	0.034	0.104	0.007
1971	11448	93	0.142	0.0	0.131	0.011
1972	25944	94	0.161	0.0	0.156	0.005
1973	28584	93	0.145	0.0	0.135	0.009

TABLE 1.15

PLUME INTERACTION CASES

24-HOUR AVERAGE PREDICTED SO_2 CONCENTRATIONS

GREATER THAN 0.14 ppm

Year	Hour Ending	Receptor	Total Concentration (ppm)	Brayton Point Contribution (ppm)	Somerset Contribution (ppm)	Background Contribution (ppm)
1971	12816	91	0.157	0.059	0.081	0.017
1971	13104	105	0.143	0.061	0.073	0.009
1972	21504	90	0.160	0.077	0.071	0.011
1972	21504	104	0.192	0.082	0.097	0.013
1972	21504	115	0.160	0.069	0.058	0.032
1972	25464	91	0.176	0.071	0.097	0.009
1972	25464	105	0.154	0.065	0.078	0.012
1973	31272	104	0.175	0.078	0.088	0.010
1973	31272	115	0.153	0.067	0.056	0.030

TABLE 1.16

BRAYTON STATION
FULL LOAD OPERATING PARAMETERS

Parameter	Boiler Number			
	1	2	3	4
Stack Height (ft)	350	350	350	500
Stack Diameter (ft)	14.5	14.5	19.5	18.5
Generation (Mw)	250	250	650	450
Flue Gas Rate (ACFM x 10^3)	705	705	1,600	1,680
Temperature (°F)	330	330	235	375
SO_2 Emission Rate (lb/hr)*	5,603	5,537	13,530	11,375

*Based on 2.2% sulfur content oil

TABLE 1.17

SOMERSET STATION
FULL LOAD OPERATING PARAMETERS
AS OF MARCH 1977

Parameter	Boiler Number			
	1	6	7	8
Stack Height (ft)	282	282	282	332
Stack Diameter (ft)	17.0	17.0	13.0	13.0
Fuel Use Rate (gal/hr)	1,440	5,940	5,580	7,680
Flue Gas Rate (ACFM x 10^3)	101.2	289.4	368.2	521.5
Temperature (°F)	375	310	310	310
SO_2 Emission Rate (lb/hr)*	512	2,115	1,989	2,736

tion, as they are on standby status. The boiler design heat input capacities on oil are taken from NEDS and shown in Table 1.18. Although Brayton Point units 1, 2, and 3 must be derated slightly when they burn coal, this small percentage would have only a minimal impact on the magnitude of conclusions sought in this analysis. Brayton Point units 1, 2, and 3 exhaust through 350' stacks while Brayton Point 4 exhausts through a 500' stack. Somerset Station utilizes 282' stacks except for #8 which utilizes a 332' stack.

Typical emission factors for oil fired units range from .02 lb/MMBtu for those equipped with ESPs to .10 lb/MMBtu for uncontrolled units. Higher emission rates would typically be the result of difficulties in boiler operation [116,117,118,119]. Although these sources report a wide range of particle size distributions, on the average roughly 50% of oil particulate emissions are less than 2.5 μm in diameter (EPA classifies particles of less than 2.5 μm in diameter as "fine"). A fuel oil sulfur content of 2.2% is equivalent to 1.21 lb/MMBtu of sulfur emissions or 2.42 lb/MMBtu of SO_2. The ground level impacts shown in Tables 1.13, 1.14, and 1.15 must be multiplied by the factors shown in Table 1.19 to calculate the ground level impact for total and specifically fine particulates. Sulfur dioxide concentrations reported in ppm must be multiplied by a factor of 2600 to yield concentrations in the desired units of $\mu g/m^3$.

Worst case numbers for power plant impact can be taken for this analysis from Tables 1.13, 1.14 and 1.15. The worst case Brayton Point SO_2 24-hour predicted impact is 0.144 ppm, and the worst case Somerset Station ground level impact is 0.191 ppm. Background concentrations for particulates will be discussed in the next section. The resulting one time worst

TABLE 1.18

Boiler Design Heat Input Capacities

Unit	Heat Input Rate (MMBtu/hr)
Brayton Point	
1	2200
2	2200
3	5600
4	4700
Somerset Station	
1	175
6	840
7	825
8	1078

TABLE 1.19

Ratio of Fine and Total Particulate to Sulfur Dioxide Emissions from 2.2%S Oil Firing

To determine ground level impact		Multiply by ratio to SO_2 emissions
Total particulate	(max)	.0413
	(min)	.0083
Fine particulate	(max)	.0207
	(min)	.0041

case ground level particulate impacts from oil firing are shown in Table 1.20. The worst case involving plume interaction has a lower impact than that shown for Somerset Station alone. According to this analysis the uncontrolled Somerset Station should contribute no more than 8% of the primary and 14% of the secondary TSP standard once in four years at one worst case location. The Brayton Point station contributes even less. Coal emissions will almost always be controlled by a particulate collection device. The Brayton Point Station has recently been given approval by the EPA to burn coal in units 1, 2, and 3. This SIP revision stipulates that particulate emissions not exceed .08 lb/MMBtu. The New England Power Co. has stated that it intends to install precipitators capable of achieving .06 lb/MMBtu when burning design coal. This level lies between the present state allowed maximum of .12 lb/MMBtu and the NSPS level for coal of .03 lb/MMBtu. Consequently, total coal emissions lie within the range specified for oil. The controlled fine particle emissions of coal will typically range from between 10% and 45% of the total [120,121,122]. Consequently, the fine particle impact of coal combustion will be somewhat less than that shown in Table 1.20 for oil.

The ERT study also computed annual average SO_2 concentrations from the series of 1-hour predictions for each of the receptor sites. The highest concentration predicted was 0.027 ppm, below the 0.03 NAAQS annual standard. The worst year for the Plymouth Ave. receptor was 1970, with a ground level concentration of 0.021 ppm predicted [123]. Contributions from the two power stations were .008 ppm from Brayton Point and .002 from Somerset Station. Multiplying by the scaling factors reported in Table 1.19 yields predicted annual TSP contributions from the two power stations for

TABLE 1.20

Worst Case Ground Level Particulate Impacts from ERT Study ($\mu g/m^3$)

Ground Level Impact		Brayton Point	Somerset Station
Total particulate	(max)	15.5	20.5
	(min)	3.11	4.12
Fine particulate	(max)	7.75	10.3
	(min)	1.54	2.04

TABLE 1.21

Predicted Annual TSP Impact of Powerplants on Plymouth Avenue Receptor ($\mu g/m^3$)

Ground Level Impact		Brayton Point	Somerset Station
Total particulate	(max)	.86	.21
	(min)	.17	.04
Fine particulate	(max)	.43	.11
	(min)	.09	.02

TABLE 1.22

Ground Level TSP Impacts of Brayton Point Predicted as Worst Case by EIS Study ($\mu g/m^3$)

	Use of Oil	Conversion to Coal (Units 1, 2, 3)
24 hour	1.7	2.5
annual	0.5	0.7

Plymouth Ave. in 1970. The predicted values are reported in Table 1.21.

Ground level impacts of the Brayton Point facility, both before and after conversion to coal firing on units 1, 2, and 3 are predicted in the Draft Environmental Impact Statement, Coal Conversion Program, New England Power Co. [109]. The Final EIS is in the last stages of preparation for release in June or July, 1979. In a telephone conversation Walden meteorologist Mr. Kiotsa explained the methodology employed for calculating ground level impacts and provided corrections to the draft EIS which will be incorporated into the final edition upon release [110]. The maximum ground level impacts resulting from full generation at Brayton Point both before and after conversion to coal as predicted in the EIS study are reported in Table 1.22 [124]. Impacts for oil firing are based on emission data, and on coal are based on the SIP provisions. The EIS study conducted and written by Walden Division of Abcor is not calibrated with onsite monitoring or meteorological data. These 24-hour impacts are significantly lower than those predicted by the worst case methodology employing the ERT study, but the annual predicted impacts are consistent. The EIS study predicts that background TSP levels alone will cause exceedances of the TSP secondary standard.

3. Secondary source influence on ambient particulate levels

The previous section has concluded that as a worst case the Brayton Point facility could contribute 15.5 $\mu g/m^3$ to ambient particulate levels. Table 1.12 reports that at the "Brayton Point Network" measurements of 24-hour average particulate levels as high as 468 $\mu g/m^3$ were reported. The EPA S&A Division performed a microscopic, X-ray flourescence, and on-site investigation to determine the origins of the particulate matter.

Microscopic analysis attempts to visually distinguish between mineral, flyash, soot, and biological particles. Soot, as distinguished from flyash, would typically be the product of low temperature combustion such as from a fire or home furnace. The X-ray flourescence technique provides an elemental breakdown of the filter catch, and can be particularly effective at distinguishing oil ash by the presence of vanadium. A sample taken directly in the Brayton Point stack was analyzed as a reference. The on-site investigation examined local meteorological conditions, instances of demolition, street sanding, or fires which might have influenced the result. These techniques can help to judge the reasonableness of the ERT predictions.

In addition to the question of the direct impact of Brayton Point as considered by the S&A study, it is important for the purposes of this study to consider the overall impact of power generation on ambient particulate levels. The impact of power plants hundreds of miles upstream can be judged with the assistance of microscopic analysis, and in the case of oil combustion chemical analysis should reveal a vanadium trace. Flyash from coal combustion is more difficult to distinguish, but ash from all combustion should be accompanied by atmospheric sulfur in the form of SO_2 and sulfates. Power plants typically release an order of magnitude more SO_2 than particulate matter, and the atmospheric lifetime of sulfur is generally longer than that of particulates [125,126]. A National Academy of Science report states with respect to long-range transport [27], "Since sulfur dioxide emissions continually oxidize to form sulfate, distant sources are relatively more important for determining ambient sulfate levels than they are for determining ambient sulfur dioxide levels. An indication that long-term transport is more important for sulfate than for sulfur dioxide is that sulfate concentrations at nonurban sites are often greater than sulfur dioxide concentrations at those sites". Lloyd Schulman, author of the ERT study on the ambient impact of increased sulfur content fuel at Brayton Point chose to ignore long-range SO_2 transport in his analysis entirely. In a telephone conversation he cited monitoring data to support this assumption, and stated that for sources more distant than 50 miles no SO_2 impact was a commonly accepted assumption [128]. Consequently sulfate concentrations provide an indicator of the presence of long range ash transport, but the ash should constitute less than 10% of the weight of ambient sulfur. In the case of oil combustion the ratio of ash to sulfate (and sulfur dioxide near the source) must be even smaller, for as much as 70% of the solids emitted from oil fired plants can be primary sulfates (see section on Mystic 7).

Robert Boisselle of the Massachusetts Department of Air and Hazardous Materials was contacted with respect to the sulfate picture in Massachusetts [129]. He reports that local sources dominate the sulfate readings, with a concentration as high as 39 $\mu g/m^3$ having once been recorded downwind from the Salem power plant in Peabody. Mr. Boisselle reports that sporadic readings of ambient sulfates have been taken at the Fire Department in Fall River, with levels ranging to slightly above 20 $\mu g/m^3$. The annual average sulfate concentration reported for Fall River in 1970 was 14.9 $\mu g/m^3$, with the average for nonurban sites in the northeastern United States approximately 8 $\mu g/m^3$ [130].

A minimum of day to day sulfate measurements are available which could help to estimate the maximum 24-hour impact of distant power production. The EPA S&A study of TSP standard exceedances in Fall River pinpointed two of the violations reported in Table 1.12 as having been influenced by high ambient sulfate levels. Of the 156 $\mu g/m^3$ of TSP measured at North Main St. on May 21, 1975, 28 $\mu g/m^3$ was found to be sulfate. June 11, 1976 is also identified as a high sulfate day, but a measurement is not provided. The X-ray flourescence analysis showed no sign of vanadium content as observed in the Brayton Point stack filter collected on July 25, 1977. Consequently secondary formation is suspect. With respect to these violations, the report states [131], "The problem is identifying the origin of the sulfates. On June 11, 1976, sulfate transportation from outside New England probably took place; it is also equally true that local conditions were highly favorable for sulfate production." Other 24 hour sulfate measurements from the MTDC and the Connecticut Air Quality Summary [132] fail to document levels significantly higher than 20 $\mu g/m^3$. The lack of vanadium in samples subjected to X-ray flourescence suggests that sulfate material is largely formed by atmospheric transformations of SO_2. Consequently 20 $\mu g/m^3$ provides somewhat of an upper limit to the fraction of ambient 24-hour TSP which can be ascribed to long-range transport from power plants, and the bulk of this material is formed in the atmosphere.

Ambient sulfate is particularly important in determining the nature of the atmospheric submicron fraction. A study conducted in St. Louis of atmospheric aerosol observed that out of 26.6 $\mu g/m^3$ roughly 12.3 $\mu g/m^3$ of atmospheric material below 2 μm collected over a 23 hour period was sulfate, while just 2 $\mu g/m^3$ of 19.2 $\mu g/m^3$ collected above 2.5 μg in size was composed of sulfate [133]. More discussion of the atmospheric sulfate problem is contained in the section of this report on Prevention of Significant Deterioration.

Microscopic analysis reported in the EPA S&A study reported that flyash constituted between 3.8% and 12.1% of sample weights. The results of this analysis for seven samples are reported in Table 1.23 [134].

TABLE 1.23

Summary of Eastern Analytical Laboratory Microscopic Analysis

Site	Date	Mineral	Percent Flyash	Soot	Biological
Plymouth Avenue	02/09/76	87.8	5.05	4.55	2.59
	02/12/76	67.2	6.3	26.5	0
	04/15/76	75.9	4.5	19.0	0.5
	06/11/76	74.4	4.7	19.9	1.1
	12/05/76	84.5	10.1	5.4	Trace
North Main Street	04/09/76	87.0	3.8	7.3	1.9
	06/11/76	72.1	12.1	11.3	4.4

Of the TSP exceedances reported in Table 1.12, four occurred on days with wind direction which implied possible plume impact. These four cases are listed in Table 1.24 [135].

TABLE 1.24

Days with wind direction implying plume impact from Somerset or Brayton Point Stations

Date	Monitor	Possible Impacting station	Diff. in Degrees	TSP Conc.
2/20/75	Milliken	Brayton Point	15°	455
12/5/76	Plymouth	Brayton Point	22°	422
6/11/76	No. Main St.	Brayton Point	10°	175
4/12/75	Plymouth	Brayton Point	12°	191

Chapter IX of the report summarizes the analysis of exceedances. Milliken Avenue was not analyzed, "because the site was influenced by several local sources; thus, no correlation to the power plant's emissions could be made".

With respect to the exceedance at Plymouth Avenue on 12/5/76, microscopic analysis found the sample to be dominated by mineral material, and X-ray analysis found the material typical of fresh road sand and with little impact from combustion sources. The report concludes, "High TSP most likely caused by road sanding operations".

The exceedance at North Main St. on June 11, 1976 is attributed in the report to "high sulfate, re-entrainment of road dust, a local brush fire, and the construction of Route 79". Optical analysis identified 74% of the material as mineral and 20% as soot. X-ray analysis found the material to be typical of old road sand with little impact from a high vanadium combustion source.

Although no special analysis was performed on the Plymouth Ave. sample from April 12, 1975, road sweeping was conducted in the area and the S&A report states, "One of the causes of the exceedance could have been the street sweeping operation."

Additional supporting evidence of low power plant impact was provided by a Massachusetts DEQE study correlating TSP and SO_2 levels [136]:

> The Massachusetts Department of Environmental Quality Engineering has run a simple statistical correlation between TSP 24 hour values and SO_2 24 hour values as collected at the Plymouth Avenue site. In this study, they found a weak positive linear relationship between the two pollutants with a r = .31. This correlation suggests that combustion of sulfur containing fossil fuels was not

strongly associated with particulate concentration levels at this site during the period of this analysis.

The S&A study concludes that the two power plants had a minimum impact on the violations, with significant impact coming from:

1. Construction on Route 79
2. Re-entrainment of particulate from roadways
3. Street sanding
4. Street cleaning
5. Brush fires
6. Elevated regional sulfate levels

The previously discussed Massachusetts Technology Development Corporation study was designed to generate technical support for the movement of sampling monitors away from the elevated particulate levels observed near roadways. The results available at this point document the significant influence of automobiles and local sources on ambient TSP levels. Results indicate that without local sources ambient TSP standards would not be violated in any of the three sites under study, but the origin of background concentrations has not been explained. Mr. Sacks, President of the MTDC in an interview stated that 1/2 to 2/3 of ambient TSP levels at some sites are caused by automobiles. Mr. Sacks could not speculate as to the impact of power plants on ambient TSP concentrations [137].

TSP levels measured by hi-vols during the program from ground level trailers are reported in Table 1.25 [138]. Note that the results closely follow traffic volume and support the present status of Fall River as being in violation of the TSP secondary 24-hour standard. Four satellite sites were established in Fall River at the same height but at greater distances

TABLE 1.25

TSP Trailer Measurements

	12 Month Geometric Mean	Violations of the 24 hour standard: Primary	Secondary	Traffic Volume
Fall River	50	0	3	34,000
Kenmore Square	76	3	23	55,000
Springfield	88	9	49	83,000

from Plymouth Avenue. None of these sites registered violations of the secondary TSP standard. The Task 5 draft final report on spatial distribution of TSP predicts the percentage of ambient levels due to local contributions by taking the difference in concentrations between satellite and trailer locations [139]. These results are shown in Figures 1.5 and 1.6. The definition of "local" must be interpreted by the distance which monitors are positioned with respect to Plymouth Avenue. The trailer sampler is 25 m from Plymouth Avenue, while the four satellites are placed at distances of 50 m, 50 m, 85 m, and 105 m. Individual satellite averages were 64% , 66% , 72% , and 57% of the trailer average concentration respectively.

Continuous samplers were operated in Kenmore Square and Fall River to determine the diurnal variation of respirable and course particulate fractions, with the cutpoint between the two fractions established at 3.5 μm. Although respirable particles exhibit concentration variations on a day to day basis, within the period of one day levels were relatively constant. Coarse particle concentrations on the other hand follow local hourly traffic levels rather closely. Figure 1.7 taken from the draft final report on hourly particulate and traffic level data shows the average Fall River concentrations for the two size fractions compared to traffic volume. Note

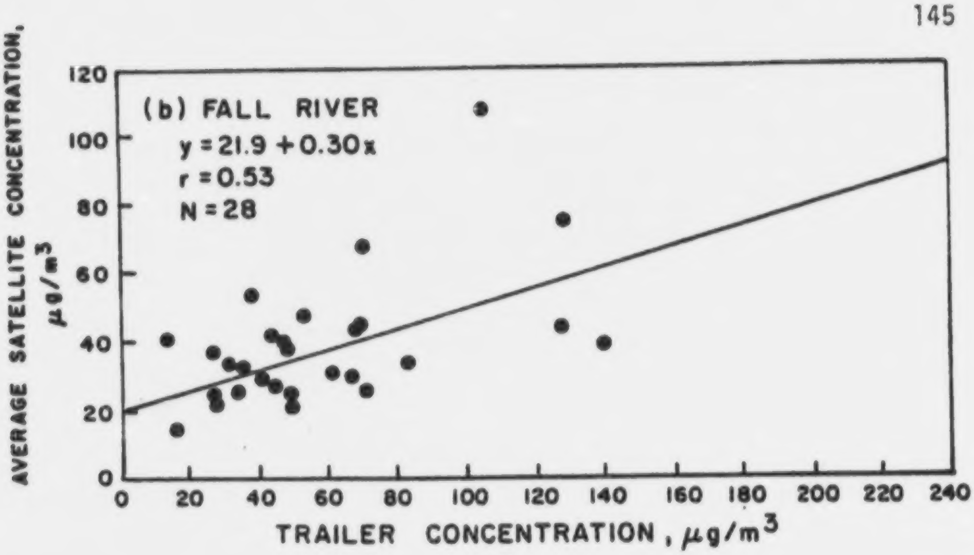


Figure 1.5 Relationship between 24-hour TSP concentration at the trailer and the average concentration at the four satellites.

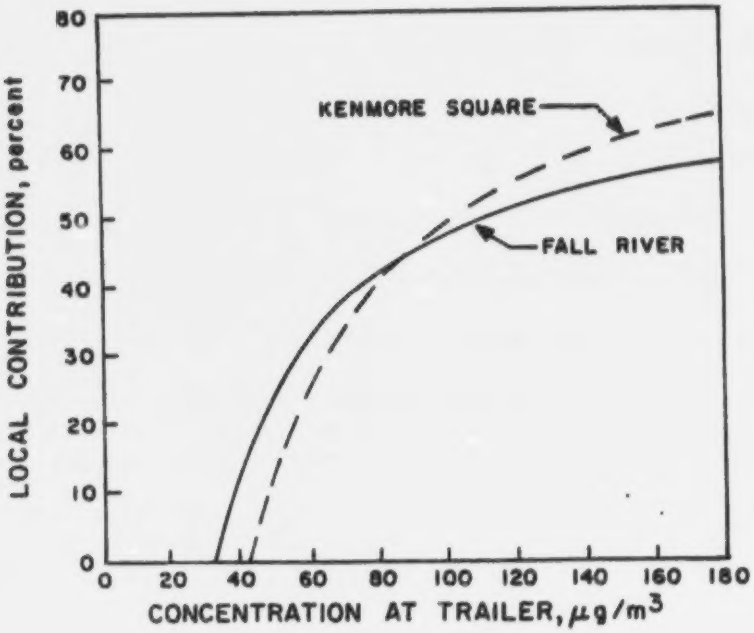
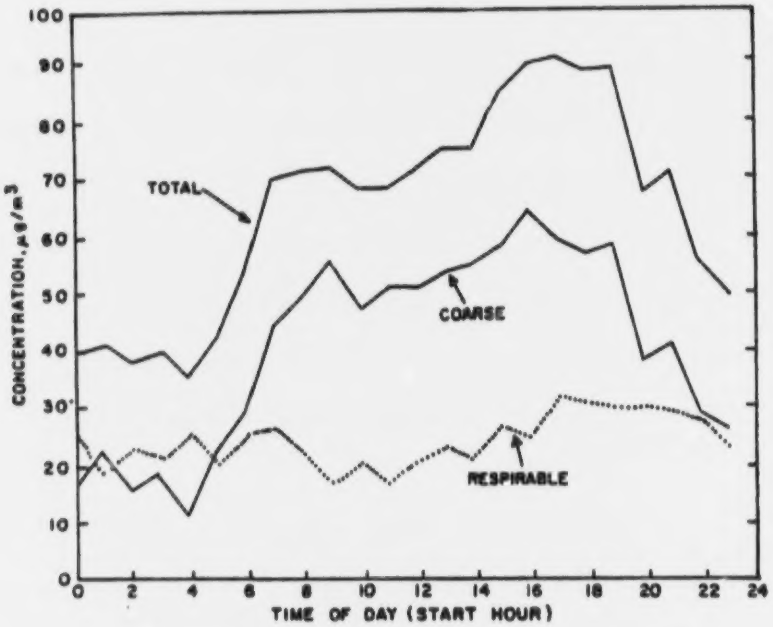
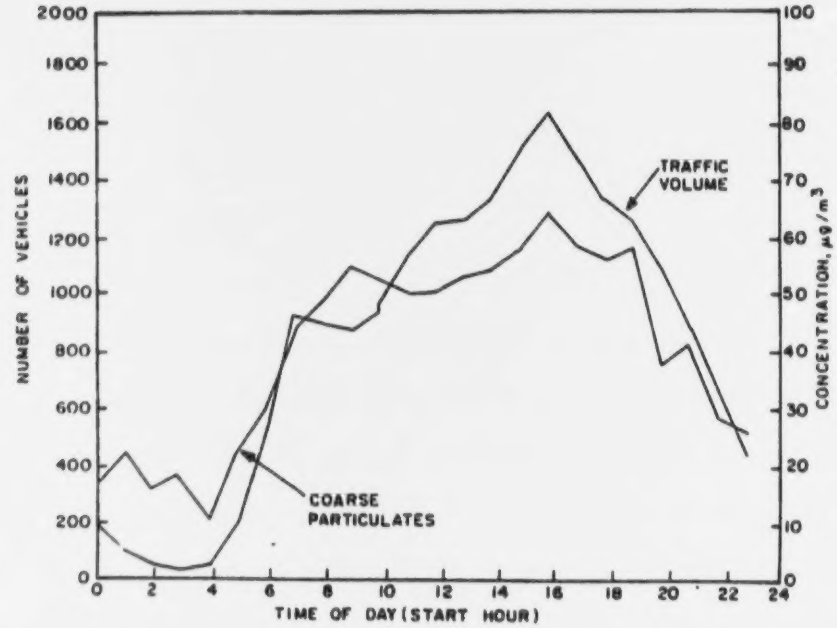


Figure 1.6 Percent of trailer concentration attributable to local contribution at Fall River.



a. Diurnal variation of APM concentrations



b. Diurnal variation of coarse particulates and Plymouth Avenue traffic

Figure 1.7 Diurnal variation of particulate concentrations and traffic volume at Fall River during March through June (weekdays only).

that traffic volume on Plymouth Avenue peaks in the afternoon period, while the coarse particle fraction shows both morning and afternoon peaks similar to the areawide traffic pattern. The authors state, "This suggests that at least some portion of the coarse component is suspended and transported over distances of greater than several dozen meters."

Average concentrations in Fall River were computed as a function of wind direction and size and are reported in Table 1.26.

TABLE 1.26

Mean particulate concentrations by wind direction in Fall River as a function of size ($\mu g/m^3$)

Direction	Frequency	TSP	RSP	CSP
N	0.105	52	26	26
NE	0.044	60	22	35
E	0.036	52	22	28
SE	0.059	54	29	23
S	0.095	70	32	37
SW	0.174	75	36	37
W	0.332	76	26	48
NW	0.157	84	26	55

Note that the respirable fraction is highest during periods of southwest winds, reflecting possible long-range transport from the New York, New Jersey area. The coarse fraction is the greatest during northwest winds. Brayton Point could have contributed to these higher levels since roughly 50% of oil fired emissions are in the coarse size range (see Chapter II), but perhaps more significantly the trailer lies east of Plymouth Avenue which runs NNE by SSW.

An analysis is reported for periods of high concentrations [140]:

> A tabulation was made of all hours during which the total sus-

pended concentrations exceeded 150 $\mu g/m^3$. The Fall River site recorded 127 such hours, about 6 percent of the study period. The Kenmore Square site recorded 160 high hours or about 8 per cent of the time. Review of these data indicate that precipitation never occurred, wind speeds were strong, wind directions westerly to northwesterly and traffic volumes above average. Most of the observations were recorded during the afternoon. The coarse component was most often the source of the high concentration.

Two dichotomous samplers were operated in Fall River, one on the roof of the sampling trailer east of Plymouth Avenue and the other across Plymouth Avenue on the roof of the Sunrise Fruit Store. The dichotomous sampler employs two filter papers, one collecting particles smaller than 3.5 μm and the other collecting particles between 3.5 μm and an upper limit ranging between 15 and 18 μm. Samplers were operated for 24 hours on an alternating day basis. Particle concentration in the range larger than 15 - 18 μm can be surmised through subtraction between the dichotomous and hi-vol samplers. Figure 1.8 shows the daily results gathered at the Fall River trailer [141]. Although dichotomous filters will eventually be subjected to X-ray analysis, this procedure has been delayed due to technological difficulties.

In the period from March, 1978 to January, 1979 the Plymouth Avenue trailer average size distribution was 54% respirable and 46% coarse. The geometric mean average mass concentration for the period was 44 $\mu g/m^3$. The satellite site displayed the same ratio of respirable to coarse particles. The satellite average mass concentration was 20% lower than the trailer,

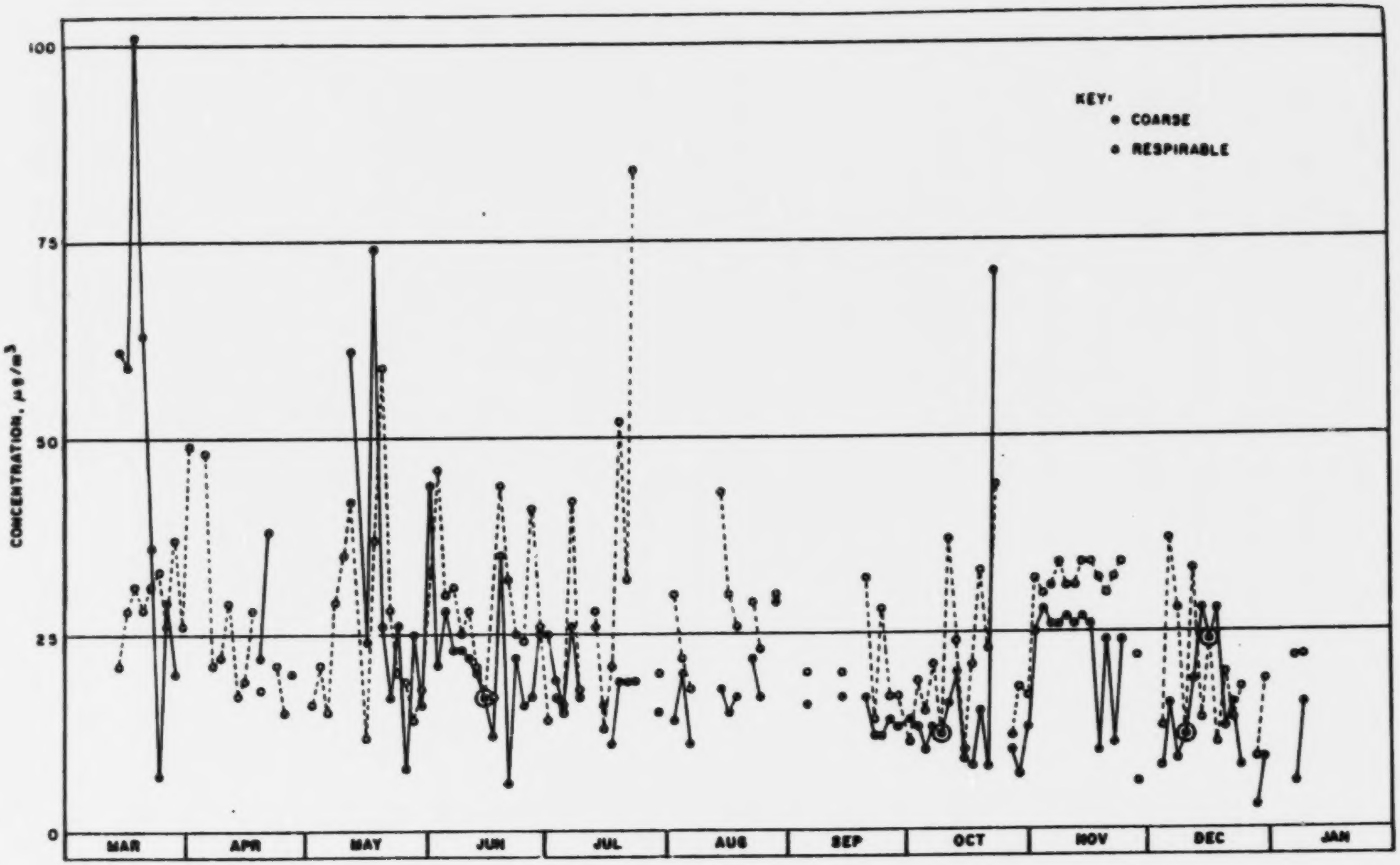


Figure 1.8 Dichotomous sampler results at Fall River trailer.

presumably due to the higher position (by 2.4 m) of the satellite monitor. The highest 24-hour concentration observed by a dichotomous sampler in Fall River was 140 $\mu g/m^3$. The EPA is presently considering an "inhalable" particulate standard which would modify the health based primary TSP standard. In contrast to the present EPA consideration, if the "inhalable" 15 um cut-point is applied to the welfare based secondary standard, Fall River would fall into compliance even for the Plymouth Avenue monitor location.

Figure 1.8 illustrates the large day to day fluctuations in both fine and respirable particulate levels. Since the 24-hour NAAQS standards are in practice the most restrictive, the maximums are of special interest. A fine particle spike is observed on July 23, 1978, and coarse particle spikes are observed on March 18, 1978 and October 23, 1978. Concentrations observed on these dates are listed in Table 1.27 [142].

TABLE 1.27

Days with elevated 24-hour coarse and fine particulate concentrations ($\mu g/m^3$)

Date	D_{coa}	D_{res}	D_{tot}
7/23/78	19	84	103
3/18/78	101	31	132
10/23/78	71	44	115

The elevated respirable concentration observed on July 23 was accompanied by persistent winds emanating from the direction of the New York City area, supporting the concept of long-range transport. Elevated coarse concentrations were accompanied by winds from 260° on March 18, and winds ranging from 170° to 330° on October 23rd. The wind direction on March 18 would tend to rule out local power plant impact, while the variable nature of the wind on October 23 would tend to minimize the potential for any significant effect. Dr. Frank Record, researcher at GCA was contacted by telephone for preliminary conclusions as the impact of the local power plants on the Plymouth Avenue monitors [143]. Dr. Record stated that in his opinion the power plant impact observed during the tests was "quite negligible".

Although X-ray flourescence data is not yet available, data gathered through chemical extraction was obtained by contacting Kenneth Wiltsee of GCA [144]. Mr. Wiltsee reports the following average chemical compositions observed during the sampling program at Fall River:

Component	Concentration ($\mu g/m^3$)
Total	61
Vanadium	.006
Lead	1.0
Sulfate	7.6
Chlorine	1.45
Silica	10.9

These preliminary results point to a wide range of contributing sources. The vanadium content of 0.17 points to a small contribution from residual oil combustion of less than 10%. The sulfate component, depending on whether the material is primary or secondary, could result from power production and long-range transport. The silica contribution along with other unmeasured abundant earth materials such as calcium and iron should be the result of re-entrainment or less likely in this location, flyash from coal combustion. The future availability of a more detailed chemical breakdown as a function of day and particle size will allow investigators to draw more definitive conclusions.

Somewhat perplexing is the observation that silica catch stays relatively constant, despite large fluctuations in total particulate collected. This effect is highlighted by the data in Table 1.28 which shows the percentage by weight of silica with respect to total particulate for Fall River in July, 1978 [145].

TABLE 1.28

Average percent silica versus TSP concentration for Fall River in July, 1978

Concentration (μg/m3)	Number of Samples	Percent Silica
16 to 39	6	21
41 to 53	6	16
53 to 75	7	17
76 to 151	7	9

This conclusion seems to imply that the automobile generated component does not contain silica. The GCA researchers conclude, "This seems to imply that high concentrations at these traffic oriented sited are due principally to greater catches of the same type of material".

The following conclusions to the MTDC study are contained in a paper slated for presented at the June, 1979 APCA convention [146]:

> The principal cause of elevated TSP levels at sampling stations adjacent to heavily travelled roadways is the re-entrainment of road sand and dust. This is demonstrated by strong correlations between hourly traffic counts and hourly TSP measurements, and the fact that concurrent elevated TSP levels were not observed at satellite monitors a short distance away from such stations. Over 50 percent

of the 24-hour TSP measurement was attributed to re-entrainment on days when the secondary standard (150 $\mu g/m^3$) was exceeded. Of perhaps more importance was the finding that over 22 percent of the material collected at the roadside station in Kenmore Square, where violations of the secondary standard were quite common, was composed of particles greater than 18 μm in diameter.

This study, thus, provides important guidance to state and local agencies involved in development of particulate control strategies. First, it is extremely important that the siting of each TSP monitor be evaluated in relation to SAMWG guidelines so that regional controls are based on concentrations representative of baseline air quality. Secondly, the degree and nature of control required for attainment in a region may be considerably different if EPA replaces the present total particulate standard with an inhalable particulate standard. Cognizance of these observations in the TSP SIP revision process could significantly change the strategies and costs of meeting ambient particulate standards.

D. Conclusion

1. Potential for particulate standard based on particle size and toxicity

The EPA is presently involved in a crash program to develop support data for potential future standards based on particle size. Evidence has been cited which documents the intent of EPA to modify the TSP primary health based standards to account for "inhalable" particles only, defined as those below 15 μm in size. The EPA is currently developing a program to evaluate the impact of a "fine" particle National Ambient Air Quality

Standard. A fine particle standard would only account for particles with an aerodynamic diameter smaller than 2.5 μm. The philosophy utilized to choose these two particle size cutpoints is described in a recent article in the Air Pollution Control Assoc. Journal by EPA personnel entitled, "Size Considerations for Establishing a Standard for Inhalable Particles" [147]. Health data is cited to show that a 15 μm aerodynamic diameter cutpoint differentiates between particles which deposit in the upper and lower respiratory tract. A cutpoint in the range of 2 μm to 3 μm is shown to distinguish particles which deposit primarily in the gas-exchange areas of the lungs. In addition, atmospheric data is cited which shows that a minimum of concentration exists for particles in the range of 1 - 3 μm, with smaller particles primarily the result of atmospheric coagulation and larger particles primarily mechanically generated. The difference in chemical composition between the upper and lower size range is cited. The paper states:

> The existence of a bimodal distribution with fine and coarse modes has been clearly demonstrated by cascade impactor studies which yield mass-size distributions and by number distribution studies which may be converted into volume distribution. These size distribution studies suggest 1 - 3 μm as the most appropriate range for a cutpoint for fine and coarse aerosols. However, practical considerations of reducing plugging of impactor orifices indicate that 2.5 μm is a more appropriate cutpoint, especially for particle size fractionating devices such as the dichotomous sampler.

The article suggests that future sampling and health research concentrate on the effects of particles in these two size ranges and with respect to a future fine particle standard states, "Data collected in the less than 2.5 μm size range could be used in conjunction with epidemiological studies to refine, if necessary, a particulate standard in 1985". It is entirely too early to project the level at which a fine particle might be set.

The director of EPA's Office of Strategies and Air Standards was contacted with respect to potential standards for particulate size and toxicity [148]. Mr. Joe Padgett's office is a division of the Air Quality Planning and Standards Branch of EPA, with primary responsibility for the formulation of new air quality standards. With respect to the inhalable particle standard Mr. Padgett replied that work was ongoing, with a final determination slated for May, 1980. Mr. Padgett explained that the EPA presently views particulates as a homogeneous class of pollutants. He feels that the agency is a long way from standards based on chemical constituents or particle carcinogenicity. He believes that there are still important unknowns surrounding the fine particle standard. According to Mr. Padgett, an important problem in standard setting is quality control for the thousands of monitoring sites operating in the country. A major concern for his office, according to Mr. Padgett, is whether field monitoring instruments are recording the same measurements as laboratory instruments. Mr. Padgett's comments are echoed in a review article on standard setting written by health scientist Mort Corn [149].

"In retrospect, it is clear that the complexities attendant upon setting air-quality standards for ambient air, when knowledge of the relationship between emissions from individual sources and air quality was, and still is, rudimentary, have led to difficulties which can only be called monumental.

It is also apparent that the principle of measurement is inherent in setting emission or ambient air standards for air quality in the United States . . . Polluted air is a complex mixture of many gases and many forms of particulate matter. Until now we have established federal ambient-air-quality standards for six individual pollutants. We have grossly oversimplified one of these, suspended particulate matter, which is not really a single pollutant but a dispersion of many sizes and types of particulate matter in air."

Gary Johnson of the EPA Special Studies division was contacted with respect to the newly created EPA Fine Particle Emissions Information System. Mr. Johnson is delivering a paper at the 1979 APCA convention describing the capabilities of this system [150]. Mr. Johnson has been gathering data for the revision of the TSP criteria document which is slated for completion in December, 1980, and for the potential particle size dependent ambient air quality standards. Mr. Johnson points out that data is not complete enough at this time to judge the impact of fine particle emitters on ambient fine particle levels. Mr. Johnson is concerned about the unreliability of cascade impactor data, the primary instrument employed for sorting particles smaller than 2.5 μm. Dave Gordon, a consultant active in air quality monitoring in the Boston area during a recent discussion referred to the use of cascade impactors as still in the area of a "black art". A fundamental strength of the proposed inhalable and fine particle standards is that they rely on the dichotomous sampler, a device relatively immune to effects of particle bounce and particle electrostatic charge.

Existing stationary sources are regulated primarily by the states through permit systems. The permit system is designed to achieve compliance with ambient air quality standards. The proposed inhalable standard would only serve to reduce the difficulties of complying with the primary health based standard, and consequently would have little impact on power plant facilities, except perhaps to allow a less rigid compliance schedule consistent with the statutory requirements for the secondary welfare based standard. The only particulate ambient air quality standard foreseeable which could affect the utility industry is the fine particle standard. This standard could both ease and stiffen the permit levels for power plants, depending on the level at which it is set with respect present inspecific TSP standards. Evidence has been cited which traces the origin of atmospheric fine particles more to the gas phase than solid phase emissions of power plants. These secondary sulfate and nitrate particles are formed from SO_2 and NO_x through gas phase transformations. Elevated particulate concentrations on the ground have been shown to be often dominated by automobile generated re-entrainment. Consequently a fine particle standard may focus on the control of gas phase emissions from stationary sources, while the focus of attention in TSP nonattainment areas may turn toward control of the automobile re-entrainment problem. Dispersion studies predict that direct power plants emissions should contribute just a fraction to ambient TSP levels.

Particular attention must be paid to recent tests which show that the solid emissions from power plants are carcinogenic. Although more conclusive evidence in this area could eventually lead to a revision of the ambient air quality standards, a much faster route to new regulation is provided to EPA through Sec. 112 of the CAA entitled, "Emission standards for hazardous air pollutants". Hazardous air pollutants can be regulated by direct national regulation through Sec. 112, but this step seems quite unlikely for a pollutant source as pervasive as the power industry. Researchers at EPRI have pointed out that the positive mutagenicity test for flyash does not necessarily imply carcinogenicity [151].

Some of the difficulties involved in standard setting are discussed in a recent article by the General Counsel of EPA [152]:

> For this audience I need not recite in detail the uncertainties one encounters in this field. Epidemiological data rarely provide a clear answer because there are usually several plausible explanations for any observed public-health phenomenon; animal testing is a crude device because the animal test population does not replicate the exposed human population in terms of either numbers or species diversity and because the test animal's reaction may differ from man's; any conclusion as to the effect of a particular chemical may fail to take into account synergistic effects that may occur as it reacts with other chemicals in the environment; and it may be impossible to measure the relative contribution of a particular source of a pollutant to the total environmental burden, and thus to assess the degree of control that is warranted for that source, etc. -- the more one looks at the data, the more uncertainties tend to proliferate.

Present data on the health hazards of flyash and oil ash seems to fall into these categories. The only particulate standards likely to be adopted in the foreseeable future based on particle size and/or toxicity are the inhalable and possibly the fine particle ambient air quality standards.

2. Effect of regulations on utility operations

Existing stationary sources are regulated primarily by the states through a permit system. In Massachusetts and Connecticut permits constrain sulfur in fuel content and subsequently sulfur emissions. Since oil is the fuel primarily utilized in these two states, the sulfur in fuel limitation also effectively limits particulate emissions. This mode of regulation could be upset by the current condition of nonattainment of TSP standards in areas of these two states. Permits for particulate emissions from stationary sources could be tightened under the following conditions:

1. If the states do not achieve attainment by 1982, sources could be forced to use "reasonably available control technology" (RACT). Although RACT is not defined in the CAA, it appears to be a less stringent requirement than NSPS.

2. A new NAAQS should force states to bring sources into compliance within four years. The most likely new NAAQS, on respirable particles, will probably serve to make attainment of the NAAQS less difficult. A future standard for fine particles or sulfates could make attainment more difficult.

3. Offset and PSD provisions in revised state SIPs could allow for new economic growth by tightening up on existing permits. Sources which adversely affect class I visibility areas and have been in operation for less than 15 years can be forced to use best available retrofit technology (BART).

4. Existing sources which have coal burning capability can be forced to use coal or another alternate fuel under the terms of the Fuel Use Act. An exemption system is provided in the act and defined in the accompanying

regulations. A cost test ratio extended over the life of the plant provides a measure which determines whether exemptions will be granted. The prohibition for petroleum use by existing facilities is discretionary to the Secretary of Energy, while the natural gas prohibition is largely mandatory.

New sources are subject at the very minimum to the restrictions already outlined for existing sources. In addition, a new source must comply with new source performance standards and stricter standards of review in nonattainment and PSD areas. The petroleum prohibition for new power plants under the Fuel Use Act is mandatory.

1. New source performance standards, recently promulgated, require that the new electric power plants achieve an emission rate for particulates of under 0.03 lb/MMBtu.

2. In order for a state to permit a new major facility in a nonattainment area one of two programs must be instituted. Either standards for existing sources must be set such that compliance is reached in 1982 with a quantified margin allowed for new construction, or an emissions offset program must be implemented. New major sources must achieve the lowest achievable emission rate (LAER), a standard potentially more restrictive than NSPS.

3. An electric power plant larger than 25 MW wishing to locate in a prevention of significant deterioration area must undergo an extensive air quality review and use best available control technology (BACT). New facilities affecting class I visibility areas are subject to BART.

4. Under the Fuel Use Act new electric power plants will generally be required to use coal or other alternate fuels.

3. Effect of new and future regulations on facilities under study

Although Connecticut and parts of Massachusetts are presently in violation of TSP ambient air quality standards, the work of the EPA S&A division and the Massachusetts Technology Development Corp. study indicate that measured levels are highly influenced by local traffic. In fact power plants seem to play only a small role in creating particulate violations, and consequently it seems unlikely that existing power plants will face particulate restrictions forcing them to use RACT or to allow for offsets. In fact, the MTDC study results indicate that the adoption of an inhalable particle standard will bring many areas into compliance with the health based TSP standards.

The adoption of a fine particle standard, on the other hand, could help or hinder the attainment of compliance in these two states depending on the level at which it is set. While the inhalable particle standard will probably be set at 150 $\mu g/m^3$, unchanged from the present level and excluding larger particles from the count resulting in a more lenient standard, a fine particle standard will of necessity introduce new allowed mass density numbers. It is difficult to speculate at this time on the level at which this standard might be set, consequently it seems prudent for the purposes of this study to be conservative. Present particulate standards in Massachusetts dictate that emission sources achieve an emission level of below .12 lb/MMBtu (see Table 1.3). The new source performance standard dictates that power plants achieve emissions of below .03 lb.MMBtu. A hypothetical standard of .03 lb/MMBtu for particles below 2.5 μm would lie between the state and NSPS emission limits in severity. This standard is employed in Chapter IV as a general benchmark for the evaluation of innovative particulate control systems. Other benchmarks may be applicable to the individual plants.

Brayton Point 2 is subject to the provisions of ESECA and the coal conversion agreement worked out in cooperation with the Massachusetts DEQE and EPA. The terms of this agreement have been described in the report section on the Fuel Use Act, and special consideration will be given to a particulate control objective of .06 lb/MMBtu for this facility on coal firing. While the state implementation plan provisions stipulate that the unit achieve .08 lb/MMBtu on coal firing, New England Electric has indicated that control equipment will be purchased which can achieve .06 lb/MMBtu.

Mt. Tom is similar to Brayton Point in that the plant is located in Massachusetts and previously burned coal. Consistent with Chapter 494 of the Massachusetts Acts of 1974, Mt. Tom could conceivable go to coal firing under the Fuel Use Act without employing an SO_2 scrubber. The Brayton Point guideline of .06 lb/MMBtu on coal firing consequently is of special interest to this facility.

Middletown 3 is in Connecticut, and with the present state regulatory climate would be forced to employ an SO_2 scrubber if issued an order to convert back to coal firing under the Fuel Use Act. Since the Fuel Use Act prohibition on petroleum usage is discretionary, it is difficult to anticipate the future impact of the act on the Middletown facility. Northeast Utilities employees indicate that coal conversion for this facility would be expensive, and it seems quite likely that the facility would be granted an exemption to FUA on the basis of the cost ratio test. Consequently, particulate hardware will primarily be evaluated with respect to the general benchmark on oil firing, with additional discussion exploring the implications of retrofit technologies on coal emissions. An assumption of no future FGD scrubbing will be made.

New Boston 2, although not presently equipped to burn coal could be subject to the provisions of the Fuel Use Act since the original design allowed for coal firing. The present Boston area limitation on sulfur emissions of 0.55 lb/MMBtu implies that economics under conversion would probably require the use of SO_2 scrubbing, depending on the availability of 1/2% sulfur coal. The New Boston facility, presently on oil firing, does not include any particulate control devices. The use of innovative technologies will be considered on coal firing to achieve the present state standard of 0.12 lb/MMBtu as well as the benchmark standard, both with and without SO_2 control. SO_2 collection schemes will be examined only to evaluate their effect on process variables, space requirements, and hardware placement.

The Mystic 7 unit is an oil-fired only unit that is not subject to the provisions of FUA. The inclusion of the Mystic 7 unit in this study provides an opportunity for comparison of innovative technologies to a state-of-the-art ESP. The present precipitator achieves the benchmark standard on oil firing. Consequently, the replacement of the present ESP by innovative technologies will be considered for achieving the new source performance standard on coal emissions. The inclusion of the Mystic 7 unit in this study allows the comparison of innovative technologies to present technology on a new unit with realistic plant parameters and site constraints.

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II. UTILITY EMISSION AND POWERPLANT SURVEY

A. Emission Data from Literature

Although much work has been done to characterize coal-fired emissions, relatively little work has been done on oil-fired emissions. Even less is known about oil-fired emissions when oil additives are utilized. Additives are almost universally utilized in the New England area to help bring flue gas dew points down, prevent ash from hardening, and help prevent air heater pluggage. Therefore, a literature review has not been particularly fruitful in learning about the emissions from plants included in this study.

The EPA document, "Background Information for Proposed Particulate Matter Emission Standards," a support document for the proposed new source performance standard on steam generators discusses oil-fired emissions (Table 2.1) [1].

TABLE 2.1

DATA ON CONTROLLED PARTICULATE EMISSIONS FROM ELECTROSTATIC PRECIPITATORS INSTALLED ON UTILITY OIL-FIRED STEAM GENERATORS

# of Sources Tested	Additives	lb/MMBtu (ng/J)	
		Range	Average
35	Yes	.021 - .244 (9.07) - (105)	.108 (46.7)
21	No	.003 - .154 (1.30) - (66.5)	.036 (15.6)

The EPA publication, "Compilation of Air Pollutant Emission Factors" [2] provides the following formula for particulate emissions from a boiler burning grade 6 oil:

$\text{lb}/10^3 \text{ gal} = 10(S) + 3$

S = Percent sulfur content of oil

Although no mention is made in the publication of fuel additives, the high value of this number implies that additives have been given some consideration.

An article by J.H. Brummer of Envirotech Corp. provides useful data on the collection of oil emissions [3]. Brummer (Fig. 2.1) shows that the emission rate from a unit burning high sulfur coal is highly dependent on excess air rate, and that a minimum of emission occurs when the stack oxygen content is 2%. The increase with higher excess air is attributed to the promotion of sulfate generation, and the increase with lower excess air is caused by the higher levels of carbon emission.

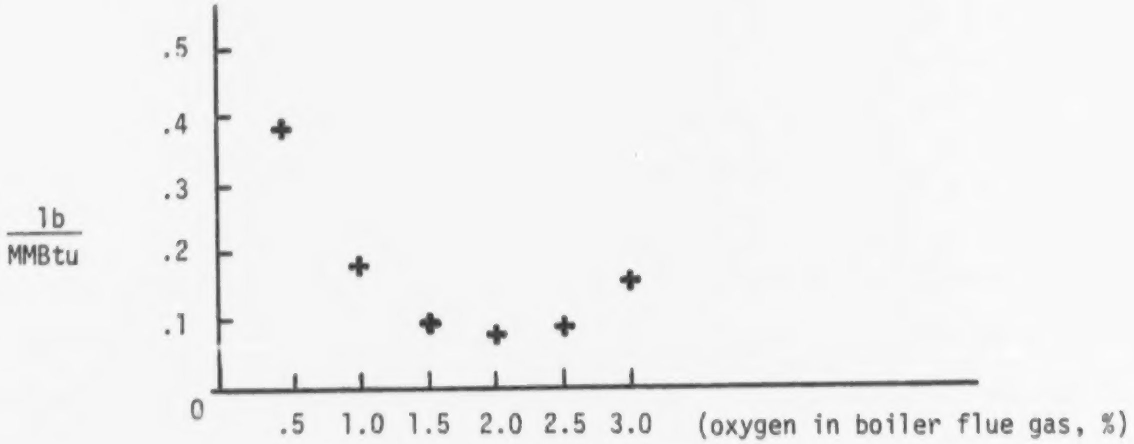


FIGURE 2.1

Uncontrolled particulate emissions as a function of excess air, 2.45% S oil.

Note that this strong dependence would not be demonstrated with coal emissions as ash quantity is not affected by excess air. Brummer also provides particle size distributions from both before and after an ESP burning the high sulfur oil, shown in Table 2.2.

TABLE 2.2

Particle size distribution measured on an oil-fired unit both before and after ESP.

Particle Size Range diameter (μm)	Before %	After %
less than .48	36	12
.48 - .72	8	2
.72 - 1.15	9	1
1.16 - 2.3	4	3
2.4 - 3.6	11	7
3.7 - 5.2	5	10
5.3 - 7.8	15	17
7.9 -12.5	4	33
greater than 12.5	8	15

Brummer notes, "The small-size material is largely sodium and vanadyl sulfates; the larger particles, agglomerated carbonaceous clusters." The larger particles generated at lower levels of excess air apparently account for the observation that the controlled emissions are lowest at low levels of excess air. This dependence is illustrated in Fig. 2.2 taken from Brummer. Brummer also supplies information on oil ash resistivity, an important issue in the use of electrostatic devices. A minimum of temperature dependence is shown between 260°F and 360°F, with values ranging between 3×10^{-7} and 1×10^{-5} mhos/m.

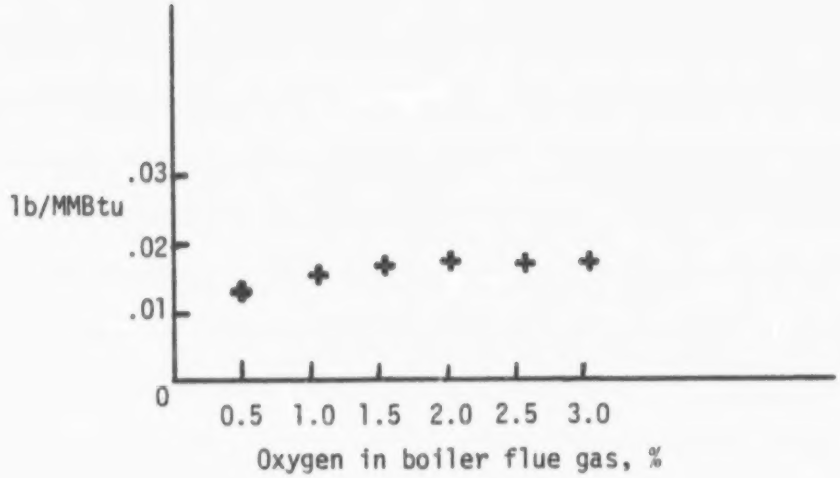


FIGURE 2.2

Controlled emissions from an oil-fired unit as a function of excess air.

Information on particle size characteristics, size and chemical composition, are provided in a paper by Cheng, et al. [4]. The elemental analysis performed by Cheng provides little additional insight above that given by Brummer. The cascade impactor study showed that oil emissions have a mass median diameter of .38 μm after a multicyclone, and coal emissions have a mass median diameter of .5 μm after an ESP.

A paper by Goldfarb and Gentry, "Particulate Size Distribution for Emissions from Oil-Fired Combustion Equipment" [5] reports the particle size distribution from the combustion of low ash crude oil in a 40,000 lb/hr (5kg/sec) steam boiler. A mass median diameter of 0.36 μm is reported for crude oil with a 0.11% ash content.

Tests on the MIT utility plant were conducted to measure the particulate emission rate. Generating approximately 100,000 lb/hr (12.5 kg/sec) steam, burning 1/2% S oil, and running 60% excess air, the boiler had an emission rate as low as .03 lb/MMBtu (13 ng/J) on one test run, with no particulate control equipment. Ash from this boiler was tested, and as expected, was extremely resistive. This result is consistent with the tests and theory of Sekhar [6]. Sekhar found that unburnt carbon has a significant impact on ash resistivity when it become greater than about 6% by mass. Conductivities of coal fly ash consistently rose from 10^{-8} mho/m to 10^{-4} mho/m once their carbon content reached 6%, the approximate point where carbon particles will randomly form chains through the surrounding ash.

Coal particle size distributions typically are much larger than those generated by oil, and are not as sensitive to combustion parameters as oil size distributions. While oil sulfur content can be two orders of magnitude greater than oil ash content, coal ash content is typically an order of magnitude larger than coal sulfur content, and will swamp out the effects of any unburned combustion material reaching the stacks.

Research efforts have concentrated on oil ash emissions since units picked for study are currently burning oil. An important task of the utility study is to adapt innovative technologies to actual utility units, evaluating the device potential against real industrial constraints. The study can be broadened to include scenarios of coal utilization by picking a hypothetical coal and gleaning design parameters from the plants and from the literature. Parameters for coal available in this region might be 13,000 Btu/lb (30kJ/gm) 8% ash and 1% S. [7]

White in a recent paper [8] lists coal flyash size distributions measured by both in stack impactor and Bahco particle classifier. Data gathered by the Bahco technique is rejected since poor resolution is often shown for the smaller particle sizes. Impactor data shows 3.9% of the mass as less than 1 μm and 9.6% of the mass as less than 2.3 μm. A manual on ESPs by Southern Research Institute shows that 1.4% of the material from a pulverised coal boiler is less than 1 μm.

B. Data on the Emissions and Hardware of Units Under Study

1. Mystic 7, Boston Edison

The most complete information to the study is from the relatively new Mystic 7 unit. This unit was brought on line in 1975, is capable of generating 580MW, and utilizes a Combustion Engineering, tilting tangential fire boiler. This boiler design is well known for its low generation of NO_x, and consequently is of special interest.

At full load the ESP processes 1.49 x 10^6 acfm (703 am^3/sec) of flue gas at 370°F (188°C). A two section Buell ESP was put in service in 1978, and features a total of 506,880 ft^2 (47,089 m^2) of plate area, with 9" (23 cm) plate spacings. The SCA of 340 ft^2/1000cfm (67 sec/m) is typical of a precipitator designed to achieve the NSPS on high sulfur coal [9]. The ESP is guaranteed to achieve a stack loading of under .005 gr/acf (.011 gm/m^3).

Particle size analysis was performed at both the inlet and the outlet of the system by Buell. Efficiency tests were performed by Air Quality Consultants under contract to Edison, and a chemical analysis of the ash samples was conducted by Environmental Associates. By combination of the Buell and Air Quality Consultants data it is possible to generate a plot of ESP efficiency versus particle size.

Figure 2.3 shows the inlet and outlet particle size distributions on lognormal paper [11]. An inlet distribution from each side of the precipitator and three stack distributions are provided. Note that the impactors are not effective at resolving the exact size distribution of the inlet material. At the north inlet 53% of the material is larger than the top 8.7 μm cut point of the impactor, and 18% is smaller than the smallest 0.32 μm cut point. The outlet distribution is similar to the inlet distribution with the larger particle fraction removed. Efficiency tests were performed on November 14 and 15 by Air Quality Consultants [12]. Six tests were performed with measurements taken at both precipitator inlets and at the stack. Gas characteristics were measured and a chemical analysis on the filter samples was performed. The first three tests were conducted without flyash reinjection, and the latter three were with reinjection. The high uncontrolled boiler emission level revealed by these tests motivated plant personnel to request that two additional sets of tests be conducted on November 16 [13]. The November 16 tests demonstrated a lower emission baseline than the earlier runs. Typical test results are shown in Table 2.3. Efficiencies shown are calculated from the data. To clarify the meaning of ash content data Ralph Wiech of Enviornmental Associates was consulted [14]. He explained that combustibles are determined by the amount of material which is lost after heating the sample to 500°C. Therefore, some sulfate species will be registered as combustible. Sulfate data is measured through titration with BaCl. Some confusion seem to exist concerning the final resting point of the magnesium oxide additive used by Edison. Mr. Wiech found no magnesium in the ash samples, although the additive seemes to stimulate sulfate generation. Mr. Zimbone of Edison reports

FIGURE 2.3 Mystic 7 particle size distribution, inlet and outlet of ESP

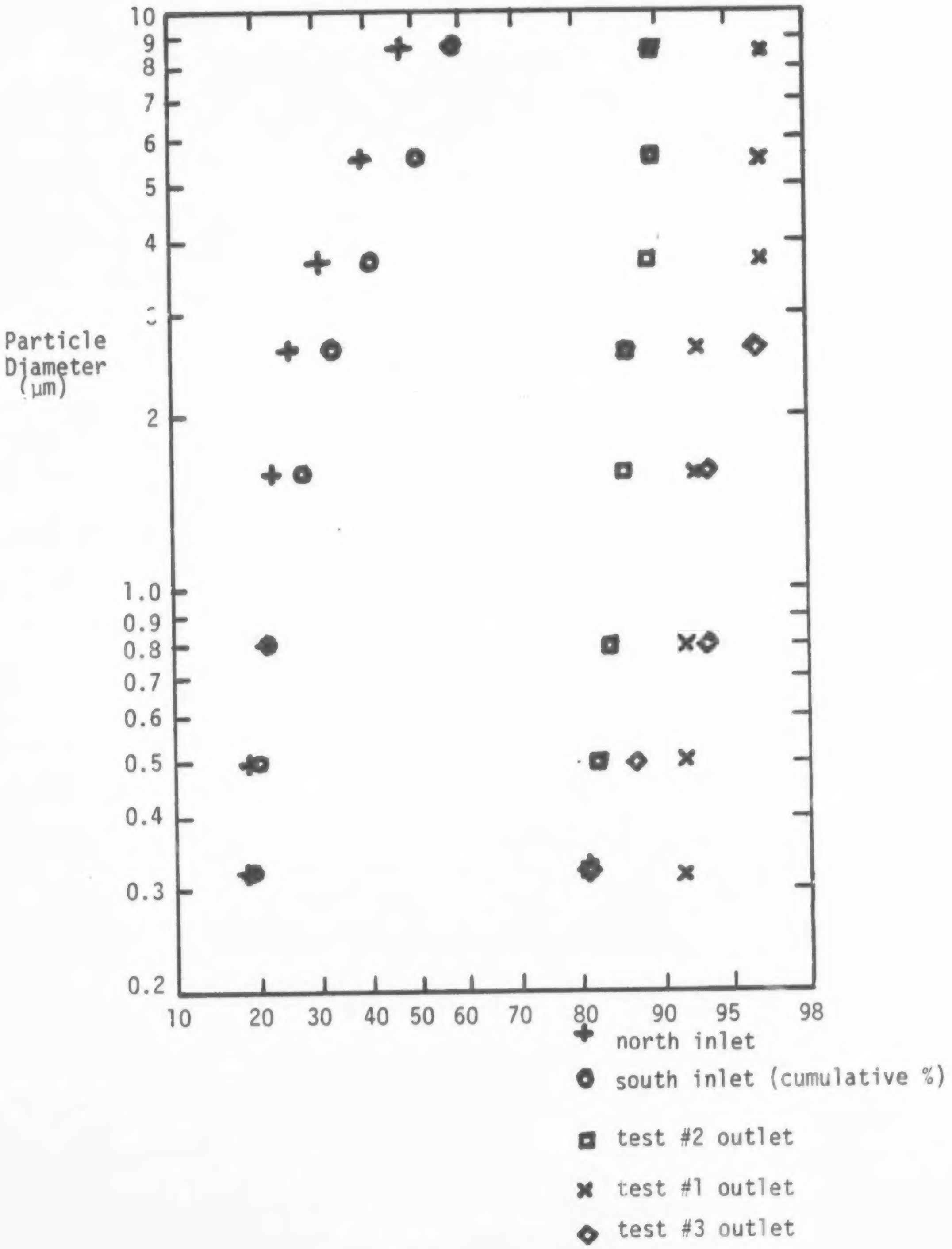


TABLE 2.3

Mystic 7 Efficiency Tests

Test (# location)	Loading lb/MMBtu	Oxygen[*] %	Combustibles %	Carbon %	Sulfates %	Efficiency %
November 14						80
1 stack	.019	5.4	50.75	4.11	41.42	
1 south in.	.10	3.8	48.47	6.09	65.21	
1 north in.	.09	3.2	57.03	8.04	na	
November 15						84
4 stack	.014	4.4	40.45	6.31	81.57	
4 south in.	.08	4.3	24.80	6.65	51.00	
4 north in.	.09	3.0	20.00	6.97	48.59	
November 16						
7 south in.	.06	4.6	57.46	1.06	na	
7 north in	.05	4.2	42.12	1.20	na	

---

[*] Oxygen data represents flue gas component. All other constituents are measured parts of the collected ash.

that 5.6 lb of magnesium is added for each 3000 gallons of fuel oil. Fuel utilized at Mystic 7 is 1%S and .04% ash.

By combination of the average of the available efficiency results and size distribution it is possible to generate an approximate efficiency as a function of size for the Mystic 7 precipitator. Figure 2.4 shows this step efficiency curve plotted along with calculated efficiencies using the Deutsch equation. For the larger particle sizes mobility is calculated by the field charging equation. Parameters utilized in that calculation are in Table 2.4. Precipitator field and current values were read off of meters in the ESP control house during the February 1, 1979 plant visit.

TABLE 2.4

PARAMETERS USED IN MYSTIC 7 ESP EFFICIENCY CALCULATION

SCA = 340 ft^2/1000 cfm = 67,000 sec/m

2S = 9" = 23 cm

Q = 1.49×10^6 acfm = 703 m^3/sec

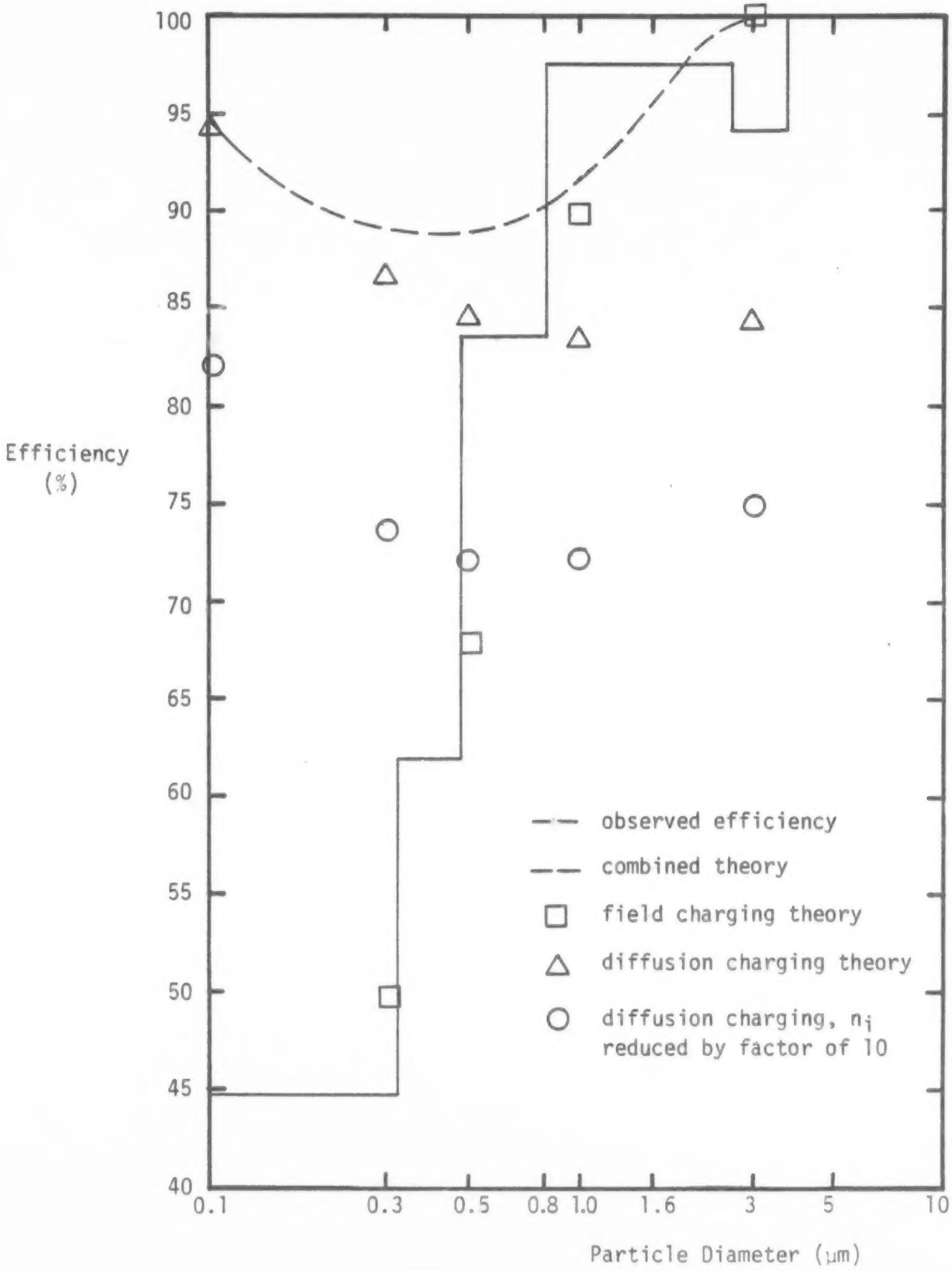
τ_{res} = 7.7 sec

V = 33 kv

E = 3.1×10^5 V/m

A calculation of diffusional charging was also performed, since this mechanism will dominate for the smaller particle sizes. The White model is employed [15] which gives a slight overestimate of charge as it assumes that the particles are in a free molecular regime. The classical diffusion equation gives a closer answer for particles that are larger than an ion mean free path, but this equation requires numerical computation. Between the particle sizes where

FIGURE 2.4 Collection efficiency vs. size for Mystic 7 ESP



diffusion and field charging mechanisms dominate an integrated solution is necessary, although the result can be approximated by simply smoothing out the transition between the two curves. Parameters used for calculation of the diffusion charge are contained in Table 2.5.

TABLE 2.5

PARAMETERS USED IN CALCULATING DIFFUSIONAL CHARGING

$T = 461°K$

$\bar{v} = 398$ m/sec

$\mu = 2.52 \times 10^{-5}$ @ 461°K kg/msec

$C = (.16 + d(\mu m))/d(\mu m)$

$J = 53$ nA/cm^2

$n_i = 4.9 \times 10^{13}$ m^{-3}

The plot of two efficiency equations shows that theory predicts a lower efficiency for smaller particles than larger particles in the precipitator. But theory does not predict the observed drop in efficiency. Deviations from predicted efficiency in ESPs is generally attributed to effects such as poor flow distribution, reentrainment, and gas bypass. Poor flow distribution could not account for the anomaly observed. Reentrainment, if anything, would skew the distribution toward larger particles. Gas bypass should affect the larger particles to the same extent that it affects the smaller particles. A sensitivity analysis was performed on the diffusional charging model by repeating the calculation with the ion density reduced by a factor of ten to 4.9×10^{12} m^{-3}. This reduced ion density would occur if a significant percentage of the observed meter current was actually passing through current leaks, or if charged particle bouncing is occurring in the precipitator. This analysis does not account for the low observed efficiency for submicron particles. It seems likely on the basis of this data that submicron sulfate particles are being generated in the precipitator. This analysis does not account for the low observed efficiency for submicron particles. It seems likely on the basis of this data that submicron sulfate particles are being generated in the precipitator. Comparison of the observed current density in this precipitator to typical values listed in a book on precipitator technology shows the Mystic value to be only 20% above that expected on a unit designed for coal with the same geometry. [16] This higher value could be typical for use with oil ash, because of the highly conducting nature of this material.

An ash sample was obtained from Mystic 7 to test for conductivity and to observe chemical characteristics. The bulk conductivity was measured as 6.25×10^{-4} mhos/m at 240°F and a low field strength of about 10 v/cm. This high conductivity would not be explained by the 1% carbon content observed on November 16, but could be explained according to Sekhar [5], by the 6% carbon levels observed on earlier tests. A small amount of Mystic ash reduced water pH from 7 to 3, indicating a highly soluble, likely sulfate content. These soluble components can also contribute to high conductivity. The high conductivity of Mystic ash would contribute to the energy burden of electrified particle bed devices.

2. Middletown 3, Northeast Utilities

Middletown 3 is a cyclone-fired unit first put in service on coal in 1964. At its full load of 240 MW, 636,000 acfm(300 m^3/sec) of flue gases are treated in the Research-Cottrell ESP. The ESP is guaranteed to provide an efficiency of 98.5% with a gas influence time of 3.16 sec [17]. More information on the present ESP is provided in Chapter IV . The unit was converted from coal to oil firing in 1973.

Efficiency results conducted in June of 1969 on the ESP show unexplained poor results. With gas velocity 15% higher than the guarantee value, an efficiency of 87.3% is recorded during soot blowing, and 64.6% without soot blowing. At a reduced load, with the facial velocity 26% below the design value and without soot blowing, the efficiency was recorded at 70.5%. Plant personnel provided this data during the January 18, 1979 plant visit, and report that the design coal, 8% ash, was in use at the time of testing.

Data is not currently available on emissions with oil firing, and an ash sample could not be obtained due to the wet ash handling system. Ron McIntyre, plant assistant superintendent reports that an oil additive is utilized which contains both magnesium and aluminum. He reports that the additive keeps ash soft, and reduces the frequency of air heater pluggage. Mr. McIntyre reports that in his opinion the ash contains 30 - 40% carbon. This high level may be the result of the low, 1% oxygen, excess air rate which is set to inhibit sulfate and smut generation.

Middletown 3 was picked for study because the excess fan power available on this pressurized unit could be used to power auxiliary pollution control equipment. In addition, it was reasoned that this unit would be a likely candidate for coal conversion and therefore would be in need of pollution hardware retrofitting.

During the plant visit and in discussions with Mr. Meyer and Mr. Buck it appears that the cost of coal reconversion is prohibitive for unit 3.

Apparently both the older Unit 1 and Unit 2 would be more likely candidates for conversion. A study by Gibbs and Hill on coal conversion costs provided by Mr. Buck, reports an incremental conversion cost for Unit 3 of $17,174,000 above fixed conversion costs which must be shared by the entire facility for the conversion of any unit [18] without the employment of FGD.

Despite the low probability of conversion, it seems prudent to study Unit 3 both with respect to potential retrofits on the present fuel, and with respect to coal firing. Retrofit options are not limited by boiler type and condition as much as they are by ash properties and space limitations. Middletown 3 currently burns 1/2% S oil, with an ash content which varies between .01 and .04%.

3. Mt. Tom, Northeast Utilities

Mt. Tom is a front-fired Riley Stoker boiler originally placed in service in 1960. The unit was operated on coal firing up until 1970 when it was converted to oil. At its nameplate rating of 136MW the unit generates 424,116 cfm (200 m^3/sec) of flue at a stack temperature of 278°F. The emission control inventory consists of a multiclone followed by a two-unit, two-section ESP. The dimensions and a sketch of the ESP are provided in Chapter IV. The ESP employs 6' x 24' (1.8m x 7.3m) tin plate curtains with wires and plates on 10" (25.4 cm) centers. Two GE high voltage supplies are utilized with a supply capability each of 1/4A @ 50KV. The ESP is guaranteed to remove 95% of the flyash from a 400,000 cfm (189 m^3/sec) gas stream laden with 2.9 gr/ft^3 (6.6gm/m^3). For emissions with more than 35% of the material below 10 μm, the guarantee is decreased by .1% for each additional 1% of the material in this smaller size range [17].

Bob Miller, operating supervisor of Mt. Tom provided information on current operations during the plant visit of January 17, 1979. He reports that on oil firing the collector yields a minimum of ash, roughly a bucketful from each of the four hoppers per day. The possibility that the unit be converted to coal or allowed to burn higher sulfur oil was raised during the plant visit by Mr. Miller, as well as Mr. Meyer and Mr. Buck from Northeast Utilities. A MgO additive is currently utilized. The use of an additive in conjunction with a higher sulfur oil could raise questions concerning the unit's particulate emissions on oil firing. On the present 1% S oil no data was made available concerning the unit's controlled or uncontrolled emission rate. The unit employs two F.D. and two I.D. Westinghouse fans to achieve a balanced draft, but Mr. Miller reports that no excess fan power is available to power extra emission control equipment. The 2.6" W.G. presently used to power the multiclone could conceivably be shifted to another type of hardware if proper flow straightening could be achieved in the small space available between the ESP inlet and the Ljungstrum airheater.

Mr. Miller reports that in June of 1965, coal with 21 - 22% ash content, 2.5%S, and from 11,400 to 12,000 Btu/lb. (25.4-27.8 KJ/gm) was utilized. Tests conducted by Tighe and Bond on flyash from June 2, 1964 show that ash carbon content varied from 3.9% to 12.7% as the highest recorded value. The higher carbon levels were typically seen when a mill was out of service and coal was therefore not as well pulverised upon injection. According to the paper of Sekhar already cited [6] these higher levels of ash carbon could have a negative effect on particle bed collection technologies, since the higher ash conductivities cause particle beds to require more current. Conversely, in the case where low sulfur coal is utilized the higher carbon levels can reduce ash resistivity and improve the operation of an ESP.

A sample of Mt. Tom oil ash was obtained from Bob Miller for conductivity analysis. At 200°F and a field strength of approximately 380V/m a conductivity of 1.3×10^{-5} mhos/m was measured. A test with litmus paper and water revealed that the ash is also quite acidic. Heating of a sample of the ash yields a sulfurous odor and some combustion.

Mt. Tom provides an excellent opportunity for study of a unit which could change fuel utilization, either toward higher sulfur oil or coal, and for which an increase in pollution control inventory might be necessary in order to allow the plant to burn the less expensive fuel. If the plant switched back to coal under the auspices of ESECA an emission level of below 0.12 lb/MMBtu of particulate could well be mandated. Using high-grade 13,000 Btu/lb (30.2 KJ/gm) 8% ash coal an emission control efficiency of greater than 98% would be required. This emission reduction level could be mandated on a daily averaging basis, requiring the efficiency design level to be somewhat higher in order to account for fluctuations in operating performance and fuel characteristics. This performance level is significantly beyond the capabilities of the present control system. The requirements of the plant if it were to burn higher sulfur oil are somewhat unclear. The uncontrolled emissions could rise above a mandated level of .12 lb/MMBtu (52 ng/J), and the capabilities of the present equipment on these emissions is undocumented.

4. Brayton Point 2, New England Electric

Brayton Point 2 is a Combustion Engineering tangentially fired boiler, capable of firing both oil and coal. The unit has a generating capacity of 252 MW on oil firing and 200 MW on coal firing [19]. As discussed in the section of this report dealing with the Fuel Use Act, the Brayton Point facility is slated for conversion back to coal firing under the auspices of

ESECA. Brayton Point Units 1 and 2 are identical units put on line in 1963 and 1964 respectively. Although Brayton Point units 1, 2, and 3 burned a total of 1,202,941 tons of coal during 1974 and 1975 under the terms of a special EPA variance [20], extensive modifications to the unit are planned before coal will be burned under the terms of the ESECA Notice of Effectiveness. Nino Molino, Principal Engineer with New England Electric estimates that conversion for the three units will cost \$30 - \$40 million [21]. Current plans call for new precipitators to be placed in series with existing collectors in order to achieve a design efficiency of .06 lb/MMBtu and leave a margin for compliance with the mandated emission level of .08 lb/MMBtu.

The Brayton Point facility lies on a point of land jutting into Mount Hope Bay in Somerset, MA. Table 2.6 lists nominal plant parameters on coal firing [19]:

TABLE 2.6

Brayton Point 2 nominal plant parameters

Generating capacity, MW	250
Average capacity	59%
Maximum coal consumption, ton/hr	77.5
Maximum heat input, MMBtu/hr (based on 12,500 Btu/lb coal)	1938
Stack height, ft. above grade	352
Maximum flue gas rate, acfm	717,870
Flue gas temperature, °F	260

The Brayton Point facility has burned both 1%S and 2.2S oil in the last several years due to changes in the state emissions permit. On May 21, 1979 the EPA allowed permanent incorporation of the regulation allowing 1.21 lb/MMBtu (equivalent 2.2%S oil) sulfur content fuel usage at Brayton Point into the Massachusetts state implementation plan [22]. EPA approval for incorporation of the coal conversion plan described in Chapter I to the Massachusetts state implementation plan was announced on May 14, 1979 [23]. This plan stipulates that the unit achieve a particulate emission rate of .08 lb/MMBtu and the fuel sulfur content must not exceed 1.21 lb/MMBtu on a monthly average basis and 2.31 lb/MMBtu on a daily basis. This standard will ostensibly be met through the purchase of 13,000 Btu/lb. 7-10% ash, and 1.51%S coal. To achieve an emission rate of .06 lb/MMBtu with 20% boiler ash retention, an emission control system efficiency of 98.6% to 99.0% is required. According to Mr. Molino the present precipitators are capable of achieving an efficiency on coal of 98.4%. This efficiency was measured according to the ASME technique in 1964 on 1.5%S coal. The use of method 5 sampling will establish an even larger efficiency increment which must be made up with additional collector capacity. Mr. Molino supplied the specifications of the present precipitator as reported in Table 2.7.

TABLE 2.7

Specifications of Brayton Point 2 precipitator

Design velocity	5.15 ft/sec
Design efficiency on coal	98.4%
Collecting plate area	133,600 ft^2
Manufacturer	Koppers
Number of series sections	3
Depth of sections	9 ft, 7.5 ft, 7.5 ft
acfm at full load	716,000
Design gas temperature	260°F
SCA	187
Number of T-R sets	12

T-R control	SCR, full wave
T-R set capacity	1200 ma/set

Mr. Molino anticipates conversion to coal firing for unit 2 in 1983. Unit 2 is a balanced draft unit, with 2 ID and 2 FD fans manufactured by Buffalo-Forge. Along with the purchase of new precipicators, Mr. Molino anticipates that the present fans will be upgraded to overcome additional static. There is presently no extra fan capacity. Mr. Molino anticipates that in order to account for fluctuations in future coal characteristics present precipitator SCA will be as much as doubled, and intermittent SO_3 injection may be required. Space will be allowed for potential future installation of the high intensity ionizer.

On oil firing ash is presently sluiced out of the ESP in 12" fiberglass pipes. An air system will be utilized for coal firing. Mr. Molino estimates ash carbon content as high as 40% on oil firing, with the carbon content dependent on mill operation for coal firing.

Mr. Molino has provided a particle size distribution measured at the outlet of the Brayton Point 1 precipitator in 1972. This particle size distribution was taken during a period of 0.79% S oil usage. A lognormal distribution is reported for particles up to 3 μm in size, with a mass median diameter of 2.3 μm and a geometric standard deviation of 3. This size distribution is relatively small compared to those reported by Ray Kenison at the Salem Harbor station of New England Electric [24]. Mr. Kenison measured a mass median diameter of 8-9 μm after the ESP on unit 2 of Salem Harbor, with the distribution increasing to as large as 100 μm mass median diameter during startup. Mr. Kenison reports that through careful control of combustion parameters the startup size distribution can be reduced and conditions leading to smut fallout can be avoided. Tests conducted on Salem Harbor units 2 and

4 both collected just 10% of the total material on the impactor final filter, showing these particle size distributions to be relatively devoid of fines for oil emissions.

5. New Boston 2, Boston Edison

New Boston 2 is a pressurized Babcock and Eilcox boiler capable of generating 380 MW of electricity (net). New Boston units 1 and 2 are identical units originally put in service in 1965 and 67 respectively with a design lifetime extending to 1997. Since startup the unit has been burning residual oil, although the boiler and plant arrangement were designed to accomodate future coal firing. Equipment required for coal firing such as coal bunkers, pulverisers, burners and electrostatic precipitators are not in place and in the event of a forced coal conversion would have to be purchased. Presently the plant is burning 1%S oil, and with the present lack of particulate control equipment, an emission level of .048 lb/MMBtu was measured. This emission rate is significantly below the .12 lb/MMBtu level stipulated in the state emissions permit. Boston Edison personnel are interested in available options for complying with air pollution regulations in the event that the plant falls under the provisisons of the Fuel Use Act. In a meeting at Boston Edison offices on March 22, 1979 Boston Edison personnel commented that the cost ratio test described in the Fuel Use Act regulations was central to determining whether the plant would be eligible for an exemption from forced conversion (see section IB5). Edsion personnel expressed particular concern during this meeting for the lack of space available for coal conversion at New Boston. Space limitations and the general large capital expenditures required have apparently contributed to making the use of coal at the New Boston facility undesireable in the eyes of Edison employees. As discussed in the section of this report on the Fuel Use Act, the prohibition on petroleum usage by existing facilities is discretionary to the Secretary of Energy, so that considerable uncertainty surrounds the future impact of this law.

The physical layout of the New Boston facility provides significant obstacles to the installation of adequate pollution control equipment for coal firing. A graphical description of the plant back end will be provided in Chapter IV. Presently flue gas leaves the airheater at an elevation of 70 ft above grade and then turns upward to breech the boiler mounted stack at an elevation of 190 ft [25]. The original plan in the event of coal firing called for a precipitator to be installed above a walkway at an elevation of 118 ft above grade. This walkway is not presently in place, and is limited in extent and support capability by the present design which shows the precipitator weight transferred to one side of the boiler support structure. This method of support may not be practical for the larger collectors dictated by modern stiffened pollution control requirements. The overhead crane of the adjacent turbine room limits the extent to which precipitator support steel could be extended to the ground. In addition, the installation and operation of a precipitator at the elevation dictated in the original design could present difficulties.

Sulfur in fuel regulations for the Boston area presently stipulate the use of 1%S oil and the equivalent 0.7%S coal. Edison personnel believe that this low sulfur coal is not readily available and in the event of a forced coal conversion SO_2 collection would be required. In the event of an order under FUA it is possible that the sulfur in fuel requirement might be relaxed, but this possibility does not seem to be particularly likely at this time. The weight and maintenance requirements of present flue gas desulfurization (FGD) schemes dictate that these systems be installed at ground level.

At the New Boston facility ground level installation would dictate that flue gas must be ducted down to the ground and back up to the stacks. Charles T. Main, Inc. was commissioned by Boston Edison in 1975 to conduct a coal conversion feasibility study for the L Street and New Boston plants [26]. This study was commissioned in anticipation of future coal use legislation and concludes:

> "L" Street Station and New Boston Station occupy a common site which is in a highly congested area. There is insufficient area for storage of coal to sustain the plant during periods when coal could not be delivered on a continuous basis. Truck delivery of coal and removal of ash and sludge would have a disastrous effect on the nearby community. The cost of providing the necessary equipment to convert and meet EPA and Massachusetts regulations would be prohibitive. The capital investment could not be recovered in the remaining life of these units. This investment would result in increased rates to the company's customers electric bills as this cost would have to be passed on via a higher rate basis.
>
> An increased staff of coal and ash handling operators would be required. The staff increase has been estimated to be 23-27 people. The cost of this addition to the staff would also have to be passed on to the customers.
>
> Converting this plant to coal does not appear to be practical.

Charles T. Main concludes that conversion of the L Street and New Boston Stations to coal burning would cost the company $230,170,000 for capital expenditure in 1975 dollars. Of this expense, $14,560,000 is allowed for the purchase of electrostatic precipitators for use on New Boston units 1 and 2. An additional $6,240,000 is allowed for installation of these two collectors. This report attempts to enlarge on the C. T. Main study primarily through the consideration of alternate innovative technologies for use in place of these electrostatic precipitators. Personnel of Boston Edison found the prices listed for electrostatic precipitators to be consistent with current expenses after allowing a typical price escalator for the intervening years. Edison personnel found the C. T. Main estimates for FGD costs to be lower than current market values. The relative costs of FGD schemes are not considered here, although account is taken of the limitations which the various technologies place on space availability and equipment placement. The Charles T. Main investigators determined that the most probable place for installation of FGD and electrostatic precipitator equipment would be in the area which presently comprises the northern half of the L Street Station. Consequently, equipment presently in the L Street Station northern half would have to be relocated. During the May 10, 1979 plant visit it appeared that the old turbine room east of the plant would provide a more convenient location for new equipment. Flue gas presently heading north after leaving the airheaters would have to be piped completely around the plant for treatment in the area picked by the C. T. Main engineers.

A technology of special interest in meeting the New Boston requirements is the use of spray dryer lime injection for SO_2 collection (see Chapter III Sec. C on the Electrified Bed). This technology, still in the development phase could be combined with the Electrified Bed to solve both the particulate and SO_2 problem in a small volume. Preliminary studies have estimated that spray dryer technology may be more expensive to operate than wet technologies due to lower reagent utilization but less intensive with respect to capital investment. This tradeoff could be quite favorable in the face of uncertainty with respect to future coal quality and availability and for installation on older boiler facilities. The C. T. Main study alludes to a gradual deterioration in coal quality, apparently caused by depletion of the more favorable seams:

> Eastern Seaboard coals have been selected as the reference fuel for this study, therefore, it follows that only steam coals would be available for this application. Reliable information is that sulfur contamination will be about 0.8 to 2.5+% by weight in the near future and that it will rise gradually to about 4% by weight. Commercial steam coal currently contains about 12 to 14% by weight ash and this value will gradually rise to 16 to 17% by weight.

Clearly there is much uncertainty surrounding the quality of coals which would be available in the future. Consequently, an O&M dominated device which allows an operator to fine tune his collection according to fuel characteristics could be desireable.

The New Boston 2 unit is presently pressurized, so that with the introduction of pollution control hardware it would generally be desireable to install ID fans and convert the unit to balanced draft. Current engineering practice calls for the installation of fans at ground level if practical.

The comparison of greatest interest to Edison personnel is between the economics of innovative technologies and conventional technology (ESP) for complying with present Massachusetts permitted emission levels (.12 lb/MMBtu particulate, .55 lb/MMBtu sulfur in fuel), while burning steam coal. In addition compliance with the benchmark standard of .03 lb/MMBtu for particulates smaller than 2.5 um in size will be examined.

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III. INNOVATIVE HARDWARE SURVEY AND TECHNOLOGICAL ASSESSMENT

A. Selection of Innovative Technologies

Innovative hardware systems were reviewed with respect to their potential for solving utility pollution control problems. A literature search provided a broad selection of innovative control devices for review [1,2,3]. Many of the devices were not designed for utility applications, and were only appropriate for the problems of specific industries. Some of the devices such as the Trielectrode Electrostatic Precipitator [4] may prove to be attractive new technologies for the utility industry, but sufficient literature is not yet available for a device evaluation. From this list six devices were chosen for further study. The innovative devices studied here are each associated with a particular development group. Government sponsored experimental data is the preferred means of evaluation of a control device efficiency. System economic analysis is based primarily on data provided by promoters of the various technologies. Consequently cost figures must be carefully scrutinized.

B. Electrofluidized Bed

1. General Description

The electrofluidized bed is a particle bed particulate air pollution control device developed at MIT under the direction of Professor James R. Melcher. A fluidized bed of 1mm - 4mm particles is employed, with the particles serving as collection sites for the pollutant. Particular pollutant particles are electrically charged by corona before they enter the electrofluidized bed (EFB), and are drawn to the surface of the sand particles with an applied electric field. A fluidized bed is a system where gas is passed vertically through a particle bed and the particle bed naturally expands such that its weight is balanced by the drag of the upflowing air.

Consequently, the internal friction of fluidized beds is small, and hence these beds are described as being similar to a fluid.

A significant literature exists surrounding the use of fluidized beds for chemical processes [5,6,7]. Work by Meissner and Mickley at MIT, published in 1949, suggested the use of a fluidized bed for pollution control [8]. Experiments performed by Meissner and other subsequent researchers did not employ an imposed electric field on the particle bed.

Work performed in the Continuum Electromechanics Group of MIT for EPA on charged droplet scrubbers led to the development of the time constant approach for evaluating the effectiveness of air pollution control systems [8,9]. With this methodology air pollution technologies are compared by the gas residence time required to achieve a particular efficiency. This methodology identified particle bed systems with an electric field imposed across the particle bed as having a great potential for increasing the effectiveness of air pollution control technology. The subsequent theory developed in the Continuum Electromechanics Groups is applicable to the many different embodiments of electrified particle bed systems, although the development at MIT has focused on employing the particles in a fluidized bed. Three patents have been granted and assigned to MIT on the electrofluidized bed concept [10,11,12]. Figure 3.1 shows a 60 cfm pilot EFB applied to the emissions from the MIT oil-fired utility plant [13] and Fig. 3.2 illustrates a 320 cfm EFB applied to collecting the emission products generated from asphalt recycling. Electrified particle bed collection in the fixed bed mode was previously patented by Cole and assigned to Research Cottrell [15].

The flow rate in a fluidized bed is set by the bed particle size, and is typically 1 - 1.5 m/sec. Lower flow rates could adversely affect particle

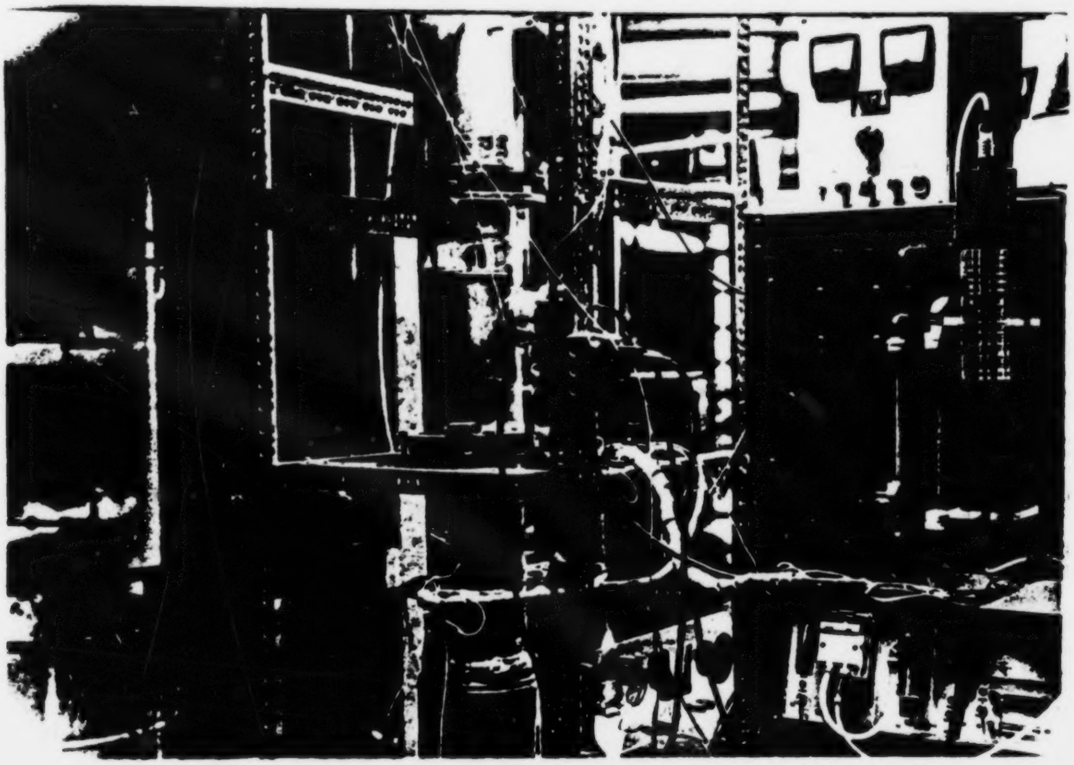


Fig. 3.1 Electrofluidized Bed 60 cfm pilot unit applied to oil fired M.I.T. utility plant.

Fig. 3.2 EFB filter with glass front removed.

removal systems which depend on the fluidization to distribute particles across the length of the bed. This problem could be offset by providing sectionalization and a damper system for turndown operation. For the collection of flyash an additive must be utilized to enhance the sticking of flyash to the bed particles. This additive will typically be fuel oil. After bed particles collect a percentage by weight of flyash they must be removed from the collection system for cleaning and regeneration. Several cleaning modes have been proposed by Alexander [16].

The EFB collector has also been proposed in an agglomerator mode, where the net collection efficiency of the system is zero but flyash particles leave the system at a much larger size than they enter. This mode requires less additive for processing of a given amount of ash than the EFB collector mode but more in total, because of the difference in ash loading from before to after an ESP. Additive is typically required at a rate equal to 2% of the weight of collected ash.

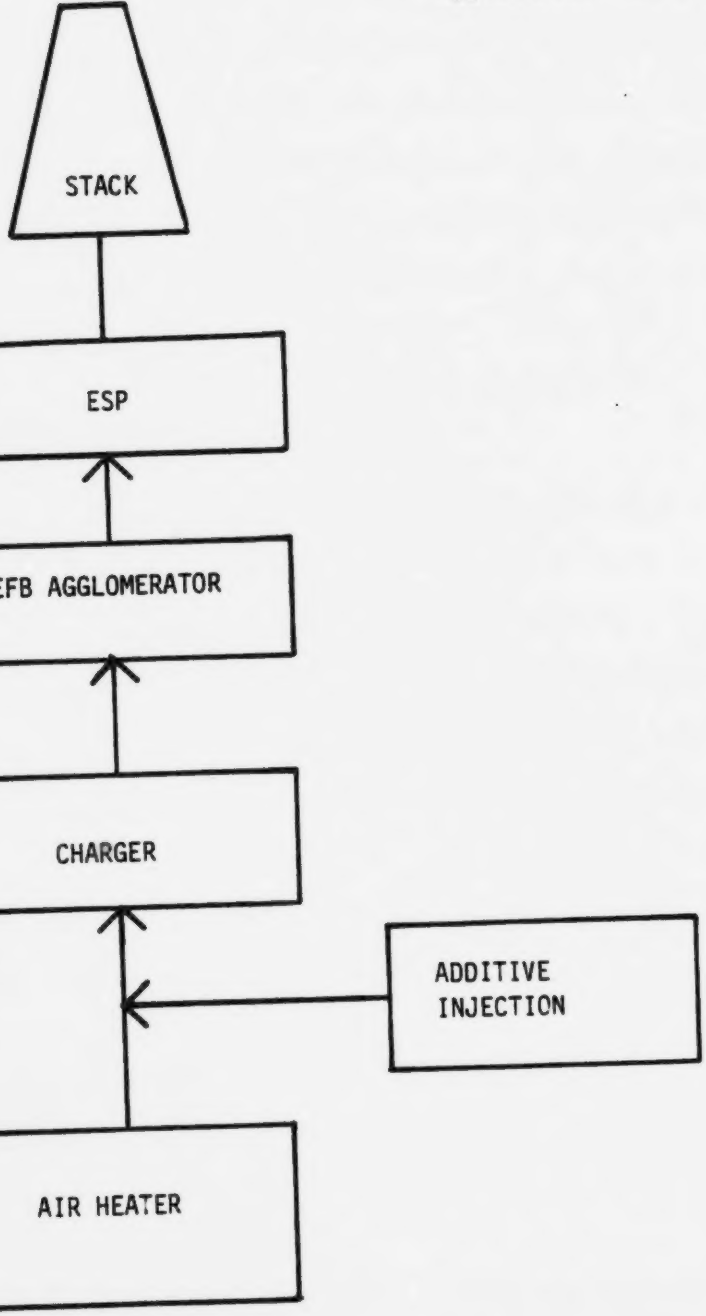
2. State-of-the-art, Development Requirements

Recent work by Alexander has focused on the application of the fluidized bed to flyash [16]. As a result of this work two general modes of fluidized bed operation have been identified. The system can be operated as an agglomerator which would necessarily precede a final collection device, such as an ESP or another fluidized bed. The EFB can also be operated as a secondary collector, following an ESP or any other dry collection system. The fluidized bed is at present not proposed as a one-stage cleaning device for use on the products of coal combustion. For any control device requiring charging and collection in separate regions it is difficult to effectively charge particles in the presence of the high ash loadings typical of uncontrolled coal combustion. An answer to the particle charging problem with the EFB could be provided by the high intensity ionizer presently under development by Union Carbide and EPRI. The high intensity ionizer is discussed in more depth later in this chapter as a potential utility retrofit device. Tests of the high intensity ionizer at the EPRI test facility in Arapahoe have indicated that even this device should be preceded by a multiclone for effective performance. This experience should apply to the electrofluidized bed which relies on conventional charging techniques.

In the electrofluidized bed agglomerator mode, bed particles such as sand are coated with a thin layer of an additive which serves to adhere ash particles to the surface. Small ash particles adhere also to each other, and eventually elutriate from the bed due to the abrasive action of the fluidization. Alexander has determined that an additive, specifically residual oil at a rate equal to 2% of the agglomerated ash, must be utilized for effective operation. The agglomerator has a zero net collection rate, but particles which come in submicron leave supermicron and are now easier to collect downstream. Alexander found that #6 fuel oil provided a suitable adhesive material for operation at 140°C, despite the fact that the flash point of the oil used was 94°C. The volatile vapors evolving from the oil are quickly carried away from the system in the low oxygen gas stream. The potential hydrocarbon emission problem has not yet been fully assessed, but could be solved through the use of a less volatile additive.

Figure 3.3 illustrates the major components of an agglomerator systems used as a retrofit to an existing ESP. The exact form of the charger, and the need for a preliminary mechanical collector, will be determined on the basis of operating conditions and fuel utilization. Alexander suggests that

FIGURE 3.3 EFB fluidized agglomerator system


STACK
ESP
EFB AGGLOMERATOR
CHARGER
ADDITIVE INJECTION
AIR HEATER

the agglomerator should employ the operating parameters shown in Table 3.1. The effectiveness of an agglomerator is judged by the amount of ash material which enters the bed in a particular size range and leaves in a larger range. Although different ash distributions will interfere with neighboring size ranges to varying degrees, Alexander reports that at 140°C, a typical stack temperature, agglomerates will begin to break off when they reach 1 - 2 μm size range. A theoretical agglomerator efficiency is difficult to calculate except for submicron particles, where an assumption could be made that all elutriating particles are supermicron. The theory of EFB collection can be found in previous works by Alexander and Zahedi [16,17].

TABLE 3.1

EFB AGGLOMERATOR OPERATING PARAMETERS

$U = 1.29$ m/sec ≡ bed superficial velocity

$l_o = 2.75"$ (7.0 cm) ≡ bed unfluidized height

$l_f = 4.5"$ (11.4 cm) ≡ bed fluidized height

$E = 2 \times 10^5$ V/m ≡ bed superficial electric field

$R = .4$ mm ≡ bed particle radius

additive of #6 fuel oil, 3% of total ash weight

TABLE 3.2

AGGLOMERATOR EFFICIENCY FOR THREE PARTICULATE CUT DIAMETERS

less than 1.1 μm	99+%
1.5 μm	71%
2.6 μm	65%

For use in this study the most accurate values of agglomerator efficiency should be those measured by Alexander. Table 3.2 reports Alexander's agglomerator efficiencies from his .024 m^3/sec hot-flow test facility for the operating parameters in Table 3.1 and three particulate cut diameters. Note that high efficiency collection of supermicron particles can be achieved with a downstream collection device. A drawing of Alexander's collector is provided in Fig. 3.4.

An EFB collector downstream from an ESP must rely on a viscous additive until the seed, now built up with flyash, can be removed from the bed for regeneration. Alexander reports that #6 oil does not provide the 1kg/msec viscosity necessary for collector operation at stack gas temperatures, but he points out that his search has been far from exhaustive [18]. Conceivably asphalt could prove to be a suitable adhesive at 140°C stack gas temperatures. Consequently, Alexander reports flyash efficiency tests in the collector mode at room temperature only. Figure 3.5 illustrates in block diagram form the components involved in retrofitting an existing ESP with a post-EFB collection system. Note that EFB collection requires that flyash periodically be removed from the bed in a regeneration step. Several regeneration modes have been suggested. If a hard seed such as sand is utilized, flyash can be removed from the sand in a screen sifter device such as is employed by EFB, Inc. It is also possible to generate seed from particles of sintered flyash. Alexander has suggested that by introducing agglomerates to the boiler it is possible to create sinters and recover heat value from the petroleum additive.

A key issue in evaluating the viability of an EFB system is whether bed materials will stay insulating after being coated with ash. If the ash is insulating it is unlikely that a problem with bed conductivity will occur. In

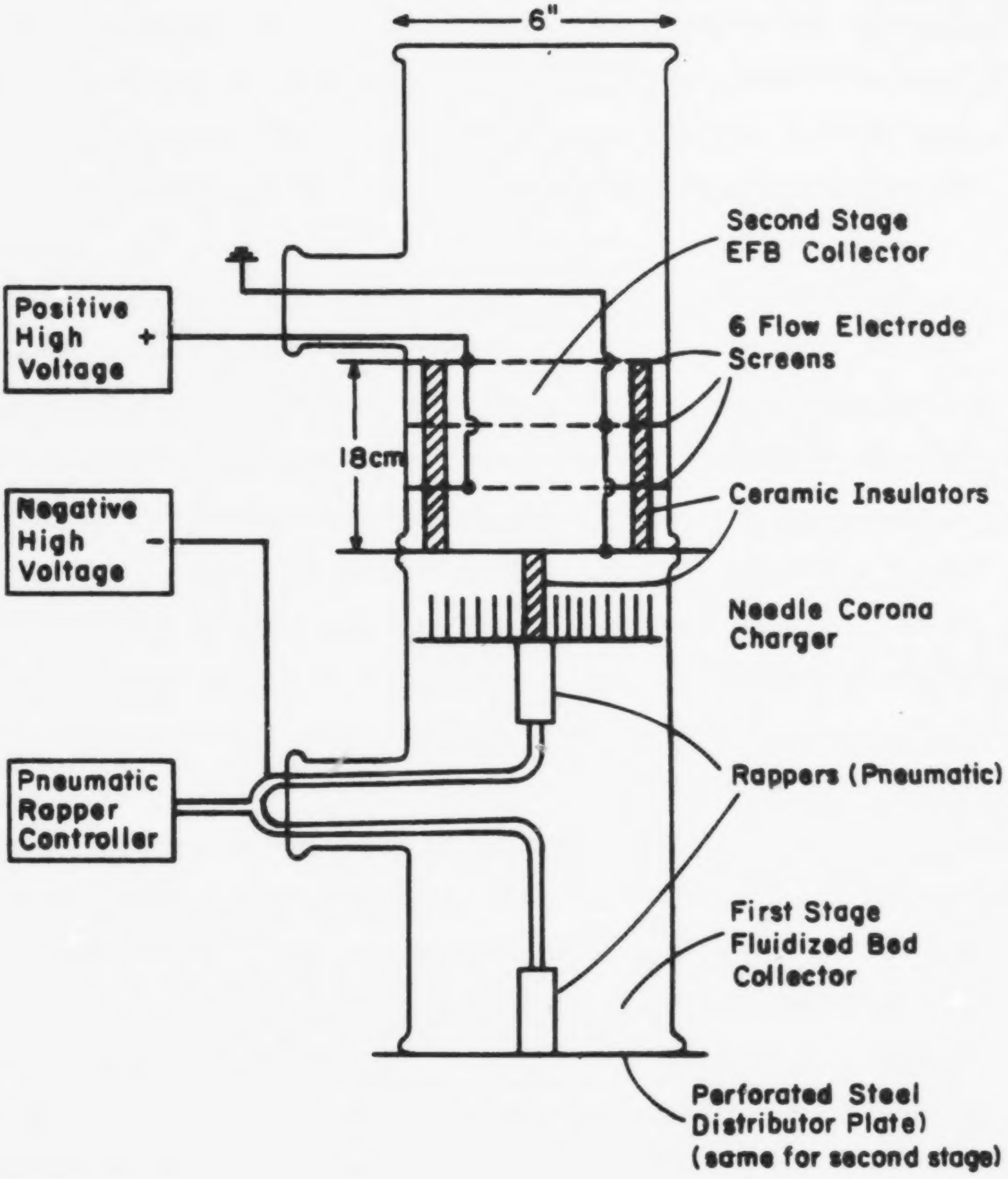
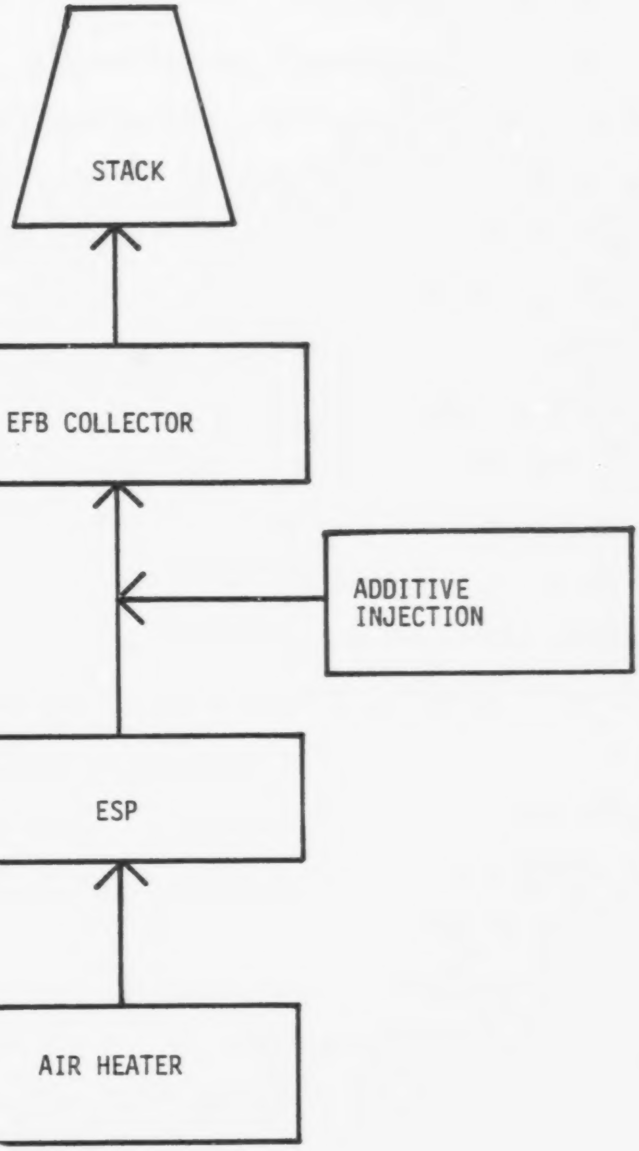

6"
Positive High + Voltage
Negative High – Voltage
Pneumatic Rapper Controller
18cm
Second Stage EFB Collector
6 Flow Electrode Screens
Ceramic Insulators
Needle Corona Charger
Rappers (Pneumatic)
First Stage Fluidized Bed Collector
Perforated Steel Distributor Plate)
(same for second stage)

Figure 3.4 FB-EFB experimental plug in bed section.

FIGURE 3.5 EFB fluidized collector system


STACK
EFB COLLECTOR
ADDITIVE INJECTION
ESP
AIR HEATER

the case of fly ash that is conducting due to a content of more than 6% carbon, several approaches to the problem can be taken. It has been suggested that the conducting nature of carbonaceous ash may be favorably modified by the oil additive. EFB, Inc. has employed glass cullet as a bed material which can be scraped clean of the collected carbon layer. Placing the EFB after the ESP may serve to render the ash a better insulator, as carbon particles are large and are therefore selectively collected by an ESP. A slight preferential collection of carbon was demonstrated by results from the ESP on the Mystic 7 station. An EFB placed after the ESP benefits from the lesser quantity of ash, and therefore less additive is required. A charger is not required, since the ESP will serve this function. And there is a possibility that ash at the after location will be less conducting.

Figure 3.6 reports the parameters for which Alexander measured the collection efficiency of an ESP followed by an EFB. The parameters used in that experiment should be typical values for the use of the EFB collector. The theory of EFB collection is dealt with in depth elsewhere [16,17].

The EFB technology, packed or fluidized, has not been tested on oil ash emissions beyond a 60 cfm (.028 m^3/sec) fluidized bed test which was conducted on a boiler of the MIT utility plant [13] (Fig. 3.1). Unlike the ash samples taken from Mystic 7 and Mt. Tom, ash from the MIT utility plant tested out to be extremely resistive. This high resistivity could be accounted for by the operation of the MIT boiler on 1/2% S fuel and excess air rates exceeding 60%. Although the cleaning procedure developed by EFB, Inc. for operation on high carbon content coal ash could be effective on highly conductive oil ash, this fact remains to be demonstrated.

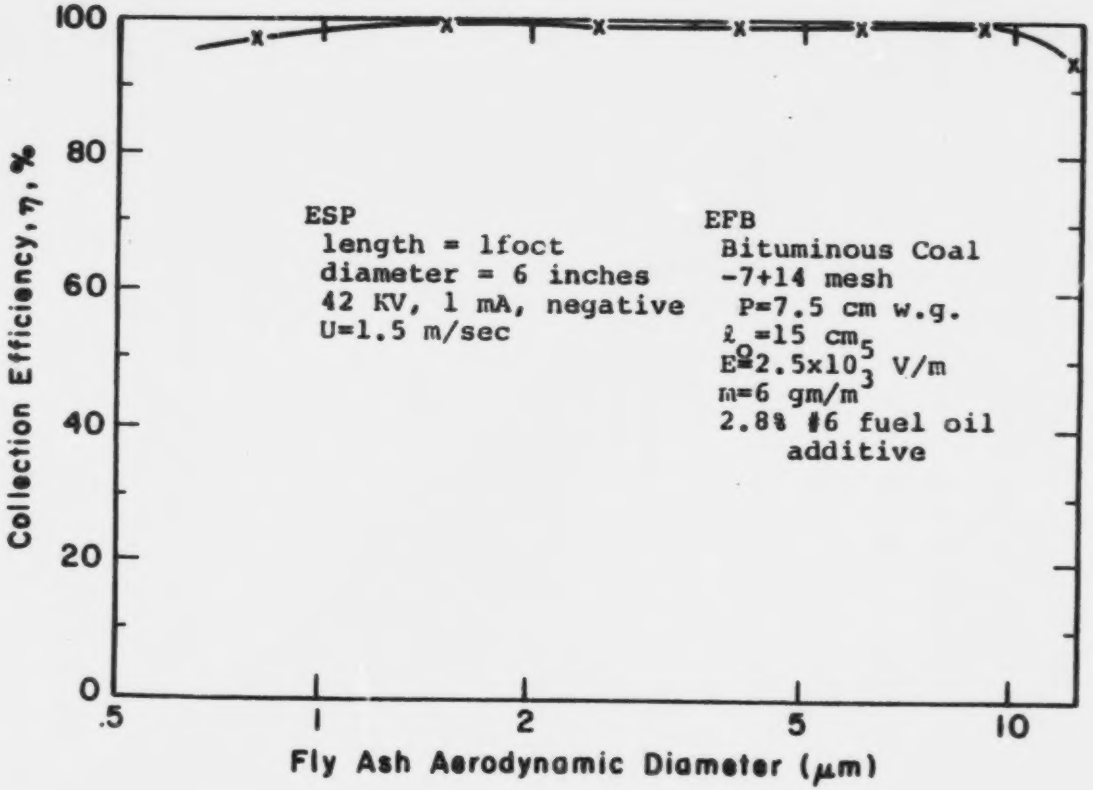


Figure 3.6 Experimental results of two stage ESP-EFB collection of fly ash.

The efficiency of fluidized beds is limited by bubble bypass. Once the velocity of gas passing through the particle bed exceeds the velocity necessary to support the bed, bed expansion begins and soon bubbles form. A theory developed by Davidson predicts that all of the excess gas passes through bubbles [5]. This theory was utilized by Zahedi to predict the efficiencies expected for a bubbling electrofluidized bed. [19]. The Davidson theory predicts that the gas bypassing through the bed in bubbles interacts with the bed dense phase at a constant rate, and that the gas in a bubble is perfectly mixed. Alexander states that the efficiency of a one-stage EFB is limited to a practical value for efficiency of 95%. Consequently, he proposes two stage systems where an efficiency of 99.75% can be achieved [20].

The Davidson model is based on fluidized beds of particles which are quite small. Consequently, a significant percentage of the total gas flow is through bubbles, and bubbles are desired to process an enhanced quantity of gas through the particle bed. Squires referred to beds of particles larger than 250μm as teeter beds, and points out that these beds are characterized by high levels of internal grinding compared to fluidized beds and a reduced level of interaction between the dense and particle phase [21]. The use of large fluidized beds of alkalized alumina for SO_2 control was proposed and studied in England by MacGrath and Streatfield [22]. They performed experiments with 2mm alumina particles and observed that Davidson's model gave good agreement only for particles up to 200μm, above which size bypass was greater than that predicted by the model.

The question of bubble bypass played a significant role in the evaluation of the EFB sponsored by the EPA [23]. This evaluation was based on 100μm bed particles which allow significantly more bubble bypass than the

2000µm particles currently employed. This study concludes that at low flow velocities good efficiencies can be achieved.

The work which led to Alexander's Ph.D. was sponsored by ESEERCO, a consortium of utilities which includes Rochester Gas and Electric (RGE). Bob Burton of RGE has enlisted Mr. Hodge of Singmaster and Breyer to evaluate the EFB concept [24]. In his review Mr. Hodge brought out seven points which he felt were worthy of further study. Most significantly Mr. Hodge was concerned about:

1. The use of an additive such as oil ot a bed material such as coal which could release volatiles at stack gas temperatures.
2. The necessity for rapping of the distributor plate and charging elements. He proposed that the requirement moght be alleviated by the employment of ac charging.
3. The possibility that the pressure drop required across the distributor might have to be higher than anticipated. Mr. Hodges states that an old conservative rule of thumb calls for a distributor plate pressure drop equal to the bed pressure drop. He quotes Zenz and Othmer who recommend that the distributor plate pressure drop be at least 40% of the bed pressure drop. Mr. Hodge performs a calculation to support his belief that 40% is not sufficient for the wide shallow beds proposed here.
4. Mr. Hodge recommends that the use of a louvered bed be considered. He cites successful application of louvered beds to air pollution control problems in industry.

3. Outline of Inherent Characteristics

Since the EFB has only been developed to a 320 cfm scale it is difficult to project what the areas of concern will be at the 10^6 cfm (472 m^3) scale.

Experimental scale-up and application of the EFB to a utility plant are essential development requirements. Significant questions surround the feasibility of using an additive, the feasibility of evenly fluidizing beds which must span hundreds of square meters, and the exact role of bypassing in reducing the high potential efficiencies of these systems.

As a retrofit to an existing ESP, the EFB offers to increase submicron efficiency to 98% with a pressure drop on the order of 8" W.G. (20 cm). The EFB offers a reduced bed conductivity compared to a packed bed due to the fluidization. The fluidization can also help to keep bed insulators clean. Significant development work is required to answer the questions of whether a particle bed can operate under the condition of high carbon boiler ash.

The agglomerator requires a minimum of auxiliary systems, as particle removal is effected in the downstream ESP. This is offset by the fact that an EFB agglomerator will require more additive than the collector, and must be preceded by an ionizer and possibly a mechanical collector. Typical electrical power consumption for the ionizer should be similar to that of the high intensity ionizer, .06 watts/acfm. Bed electrical consumption will vary over orders of magnitude, but will typically be less than an ionizer.

No economic studies have been conducted on the EFB to date. The system cost could be strongly affected by the necessity to rejuvenate particles. The vertical cross section of the collector must be similar to the horizontal entrance area of an ESP, as these devices use similar facial velocities. Flow distribution must be provided for below the bed and several feet of freeboard should be provided above before gas is turned and/or converged. Construction similar to an ESP should be acceptable, although special wear resistant materials are often utilized for distributor plates.

C. Electrified Bed

1. General Description

EFB, Inc. is presently developing its Electrified Bed granular bed filter for use on the emissions from coal and oil firing. The device consists of a louvered panel bed across which an electric field is applied by a center electrode. Figure 3.7 shows a section of the bed with the polarization of the bed granules illustrated in the blown-up circle [25]. In the EFB, Inc. device flyash laden flue gas is first passed through a mechanical prefilter granular bed. In this lower section larger supermicron particles are collected. Figure 3.8 illustrates the arrangement of the stacked cylindrical prefilter and post high efficiency filter bed in which submicron collection is achieved. After supermicron collection in the prefilter bed the gas passes up the center of the cylinder and out through the upper cylindrical electrified bed. The center of the cylinder contains an emitting wire which ionizes the particles in the gas stream. Charged particles passing through the interstices of the upper electrified bed are drawn to the caps of the electrically polarized bed particles. High efficiencies are achieved by the large effective collection surface of particle beds. Field strengths in the interstices of the particles can be several times higher than the superficial field strengths. This enhancement improves collection efficiency without placing an additional demand on insulation.

The EFB, Inc. unit utilizes a prefilter in order to minimize space charge effects and rapping frequency of the center electrode wire. In addition, the larger carbon particles which are often emitted from coal or oil-fired units can be collected in the lower stage. These carbon particles will tend to increase the conductivity of collector bed material and increase the system's

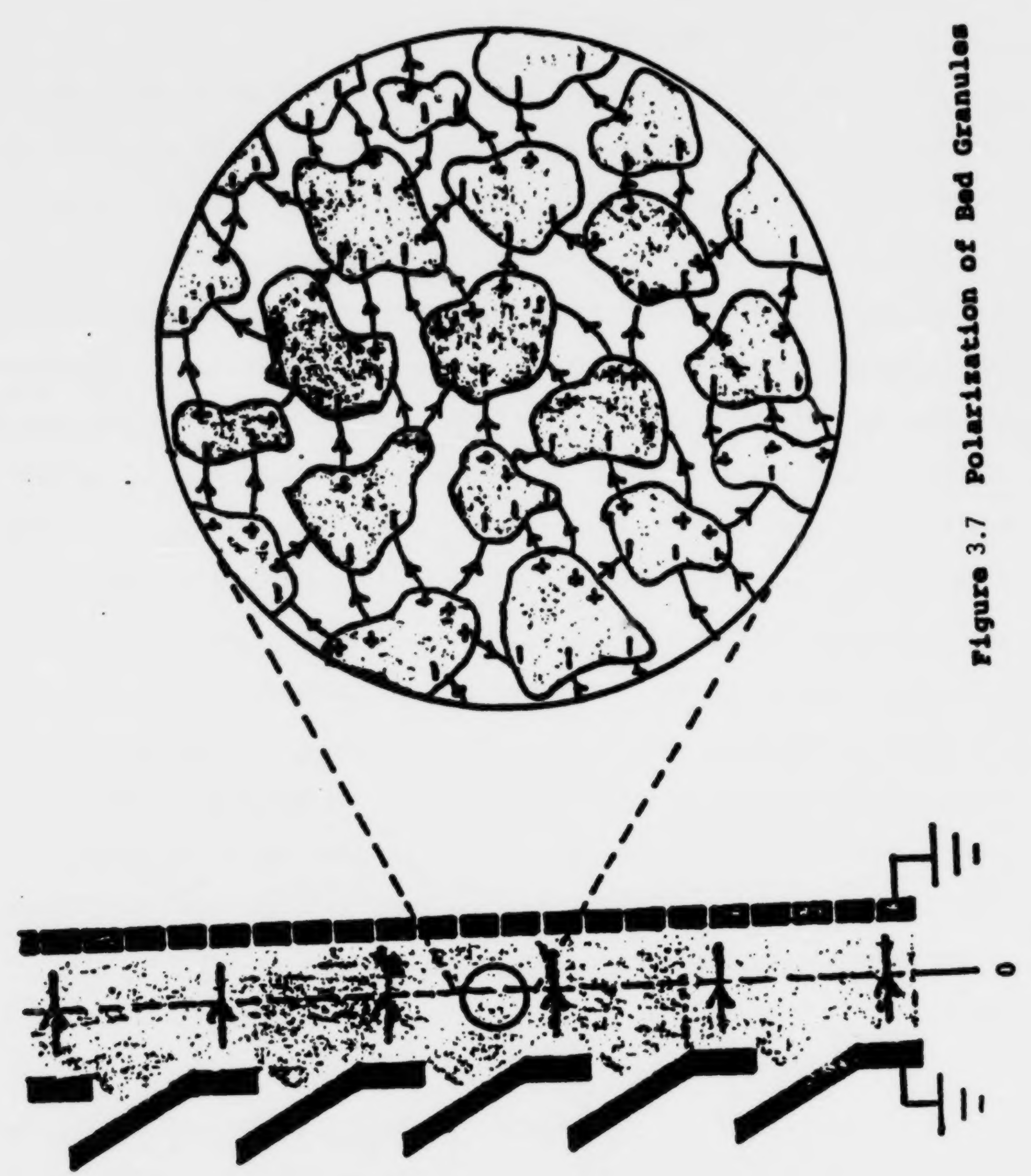
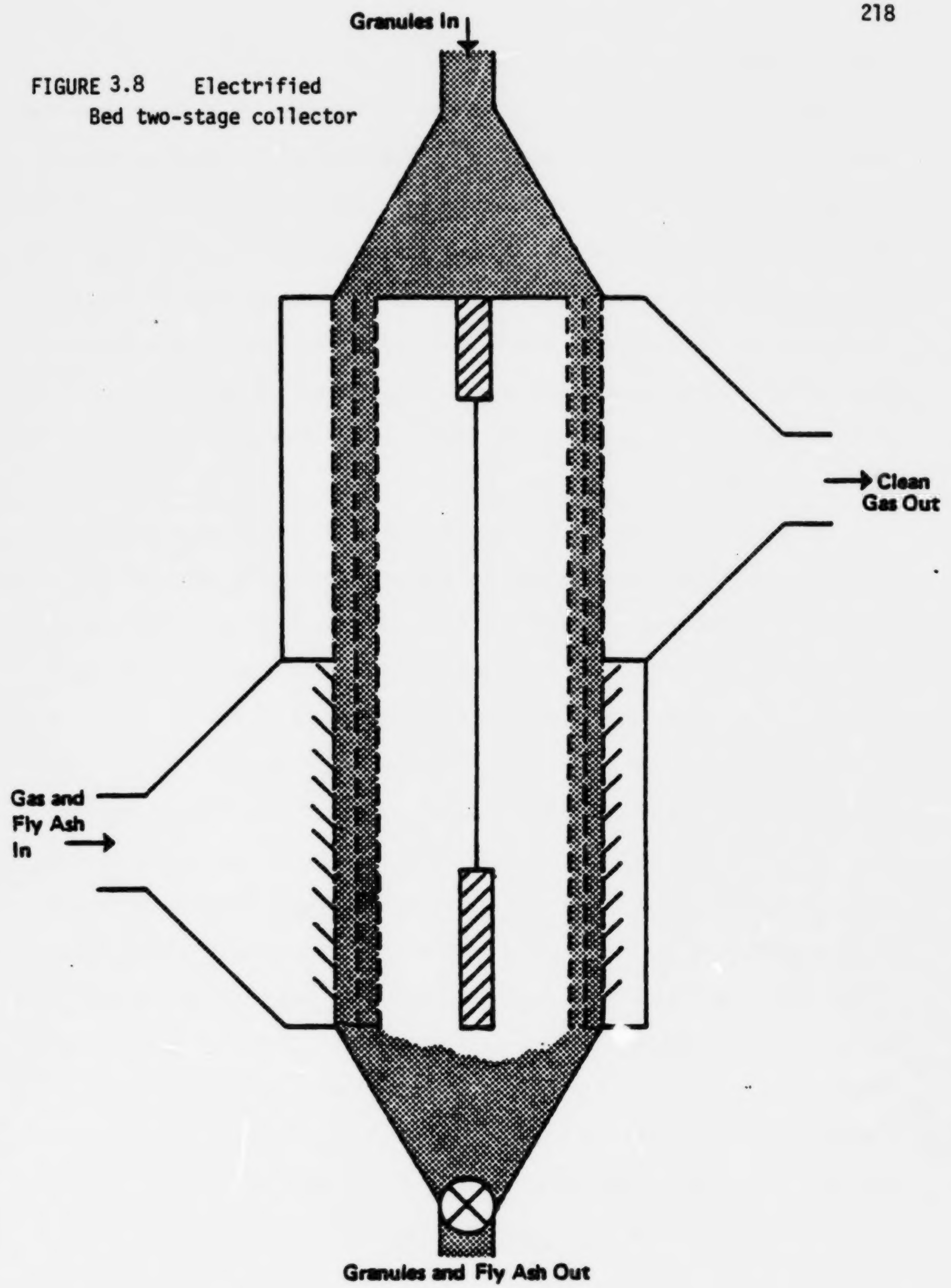


Figure 3.7 Polarization of Bed Granules

FIGURE 3.8 Electrified Bed two-stage collector



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level of power utilization.

Bed material, typically 2 mm to 5 mm in diameter, is constantly cycled down through the center of the cylinders, out through a vibrating feeder, through a cleaning section, and back to an elevator and the top of the system. Empirical tests have shown that the bed weight can be increased by up to 2% with fly ash before breakthrough occurs and the material must be removed from the system and regenerated. Regeneration is achieved in a small fluidized bed. After passing through the bed fluidization air is ducted to a bin vent exhaust system. This secondary air loop must treat between 1% and 5% of the primary airflow volume.

The Electrified Bed can be used as a retrofit device to a present ESP. Following an ESP ash loadings are low and only the second stage of the collector should be required. In addition, the ESP is effective at charging particulate so a separate charging element should not be required. The Electrified Bed is sized so that the gas facial velocity is 0.4 m/sec. In the retrofit mode tubes can be built to any practical diameter or height, as long as the upward gas exit velocity out of the center of the tube is held to a reasonable velocity such as 12 m/sec. Tubes can be closely spaced as long as the inter-tube flow is held to a reasonable level. Although the use of a larger number of smaller tubes allows the incorporation of more active volume into a particular size box, this advantage may be offset by the large number of pieces and more difficult internal access provided by the smaller tubes. Tube size will range between 3' (1 m) and 9' (3 m) in diameter. Figure 3.9 shows a 1500 cfm (.7 m^3/sec) four tube pilot plant system which has been operating on redispersed flyash in the EFB, Inc. laboratory. Through the windows the first stage inlet louvers and second stage gas exit

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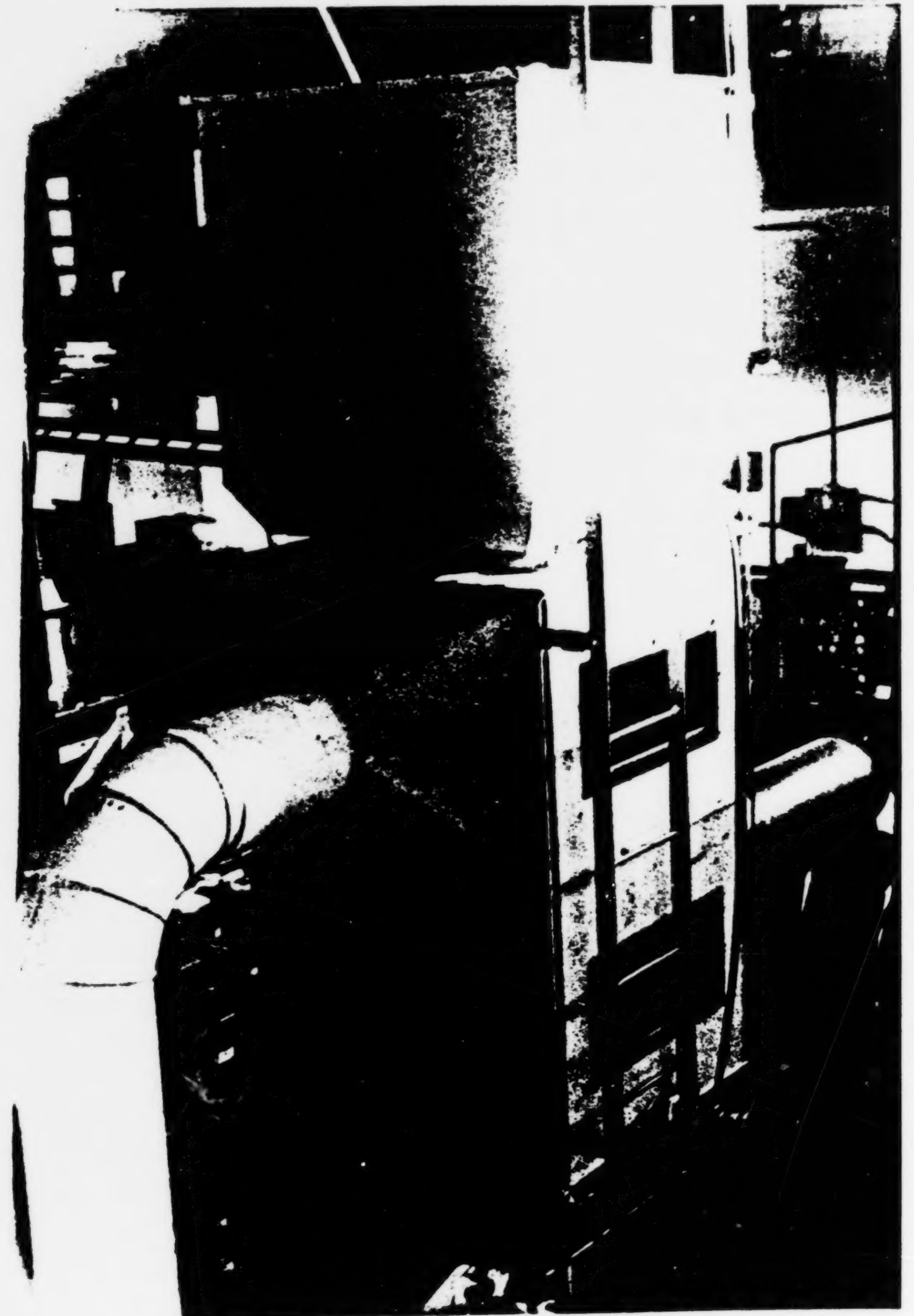

Fig. 3.9 EFB, Inc. two-stage 1500 cfm Electrified Bed flyash collector.

back plate can be observed.

2. State-of-the-art, Development Requirements

The first field test of the Electrified Bed system on coal emissions occurred in late 1978 on the #1 boiler of the AC Spark Plug plant in Flint, Michigan [25]. This boiler generates 30,000 cfm (14.2 m^3/sec) of flue gas burning 1% S, 8% ash, and 12,500 Btu/lb (29KJ/gm) coal, stoker fired. A one-tube, two-stage Electrified Bed treated 1000 cfm (.47 m^3/sec) of the flue gas. Smooth operation was achieved on the high carbon content ash by using crushed glass (cullet) as the bed material. A schematic drawing of the AC Spark Plug test setup is provided in Fig. 3.10. Cullet has a smooth particle surface which is effectively cleaned of carbon in the fluidized bed, whereas the pores on the surface of sand particles tend to fill with carbon and render the whole particle conducting.

The Electrified Bed system can take advantage of existing ESPs when used in a retrofit mode. ESPs are quite effective at collecting the larger particles, which typically contain much of the carbonaceous material. In addition, material leaving an ESP should be charged. This permits an Electrified Bed to be fitted as a retrofit to an existing ESP devoid of the prefilter stage and charging electrode. One pass through an electrified bed will typically require less than 3" W.G. of pressure drop. Efficiency should be similar to the 99% level observed at AC Spark Plug.

The theory of Electrified Bed collection is similar to the theory of EFB fluidized collection. The idealized collection model is represented in the following equation:

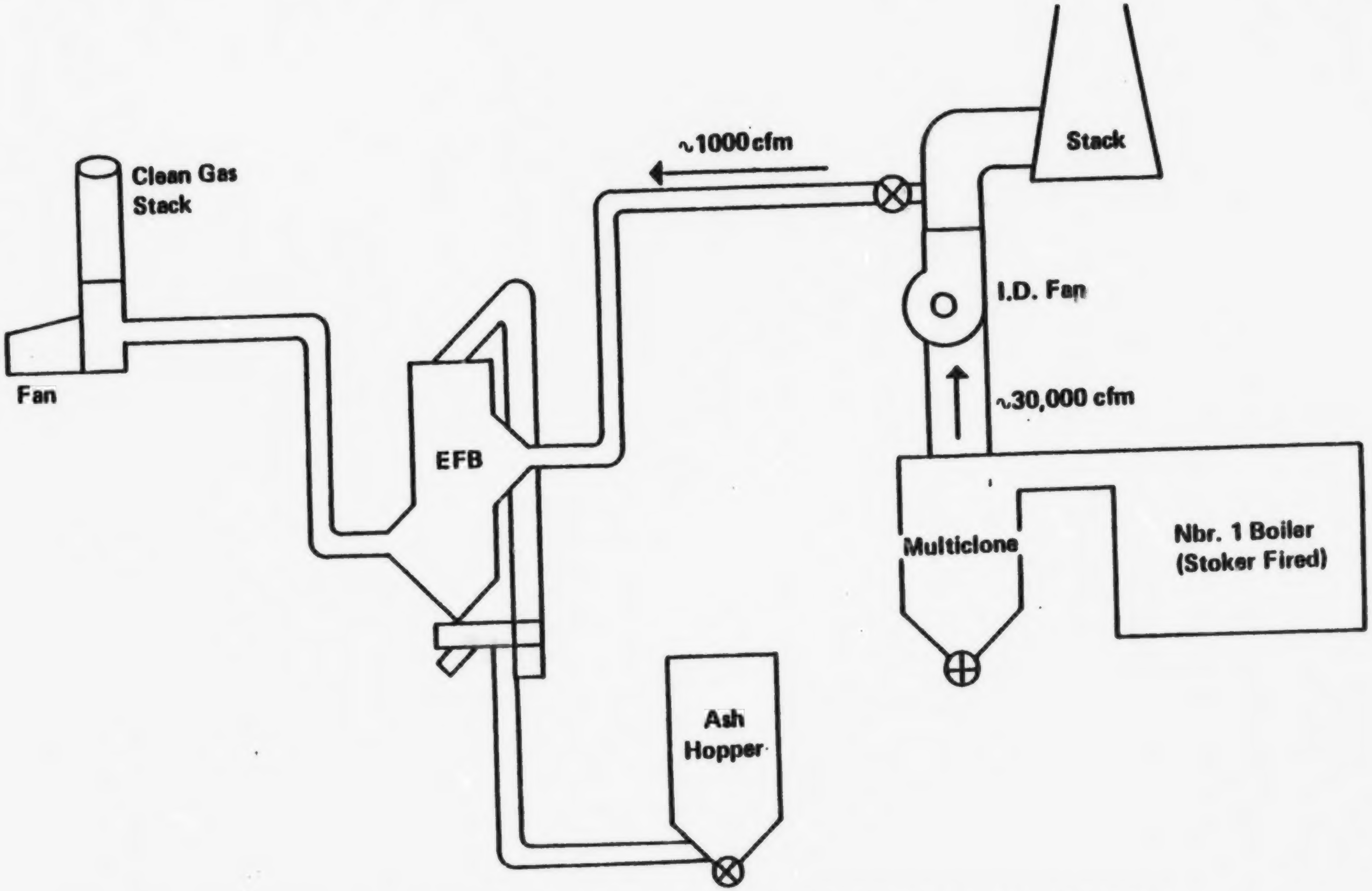
Clean Gas Stack
Fan
EFB
~1000 cfm
Stack
I.D. Fan
~30,000 cfm
Multiclone
Nbr. 1 Boiler (Stoker Fired)
Ash Hopper

Fig. 3.10 Electrified Bed installation schematic at GM stoker fired boiler facility.

$$\eta = 1 - \exp^{-\frac{3\pi}{8}\frac{\ell_o}{r}\frac{bE}{U}}$$

$\eta \equiv$ efficiency

$\ell_o \equiv$ bed depth (m)

$R \equiv$ bed particle diameter (m)

$b \equiv$ pollutant particle mobility $(\frac{m^2}{vsec})$

$U \equiv$ superficial gas velocity $(\frac{m}{sec})$

$E \equiv$ superficial electric field $(\frac{v}{m})$

It has been determined by EFB, Inc. that 5kV/in is a practical bed voltage for continuous operation in applications with conducting ash. A superficial gas velocity of 75 fpm (.381 m/sec) yields 3" W.G. pressure drop through a one-pass 4" (10.2 cm) deep bed. The pollutant particle mobility is dependent on particle size and the operating parameters of the upstream ESP. This value should strictly be calculated from theory, but experience has shown that 10^{-7} m^2/Vsec provides an adequate design value for submicron particles. Efficiency increases for larger particles in proportion to their size. These design values are summarized along with the associated submicron design efficiencies in Table 3.3.

TABLE 3.3

ELECTRIFIED BED DESIGN VALUES

$R = 2$ mm

$U = 0.4$m/sec

$b = 10^{-7}$ m^2/V·sec

$E = 2 \times 10^5$ V/m

ℓ_o = 4" (10.2 cm)	ΔP = 3" W.G.	η = 95%
ℓ_o = 5" (12.7 cm)	ΔP = 4" W.G.	η = 98%
ℓ_o = 6" (15.2 cm)	ΔP = 5" W.G.	η = 99%

Overall efficiencies will be higher when account is made of the larger particle sizes. Bed depths less than 4" (10.2 cm) are not utilized due to their lower operational reliability. Due to the employment of a prefilter bed the experimental efficiencies observed in the Flint, Michigan tests were somewhat higher than those reported in Table 3.3.

Problems were encountered during the GM tests in the form of pressure drop buildup. This buildup occurred because the second stage of the system was built with a perforated plate gas entrance as well as exit cylinder. The action of the corona wire on this perforated plate caused fly ash to accumulate and increase the system pressure drop. This problem would probably not occur with the Electrified Bed in a retrofit mode, as a charger is not utilized and only one stage with a louvered front panel is necessary. Tests by EFB, Inc. showed no pressure drop buildup on the first-stage collector. EFB, Inc. has proposed that future two-stage collectors use both louvered inlet and outlet cylinders. A test of this innovation on a 200 cfm scale has been successfully conducted in the EFB laboratory.

EFB, Inc. has also developed the Electrified Bed system for the collection of oil emissions which result from the manufacture of shingles and fiberglass. Figure 3.11 shows a 20,000 cfm Electrified Bed system collecting emissions from a shingle line at the Bird & Son plant in Norwood, MA. This full-scale system has been in successful operation since November, 1978. Two similar systems are soon to be installed at roofing plants in Canada. These systems employ 12 panel beds arranged in parallel to give a total combined bed facial area of 288 ft^2. Depending on the bed particle size, a facial velocity of as high as 100 fpm can be employed through the 3" deep beds. Presently 4 mm gravel particles are employed and the collected oil

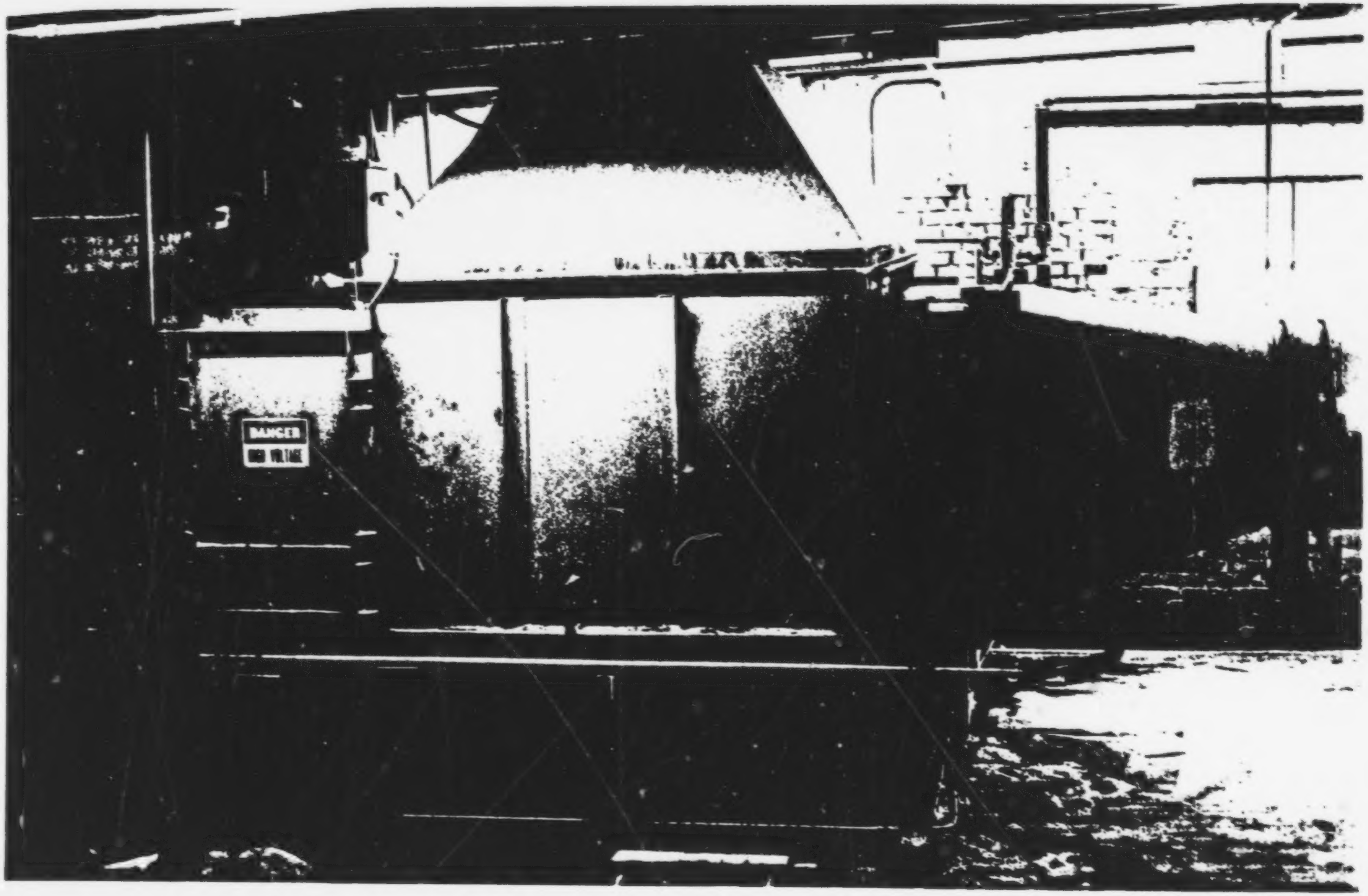
DANGER
HIGH VOLTAGE

Fig. 3.11 EFB, Inc. Electrified Bed 20,000 cfm installation at the Bird & Son roofing plant.

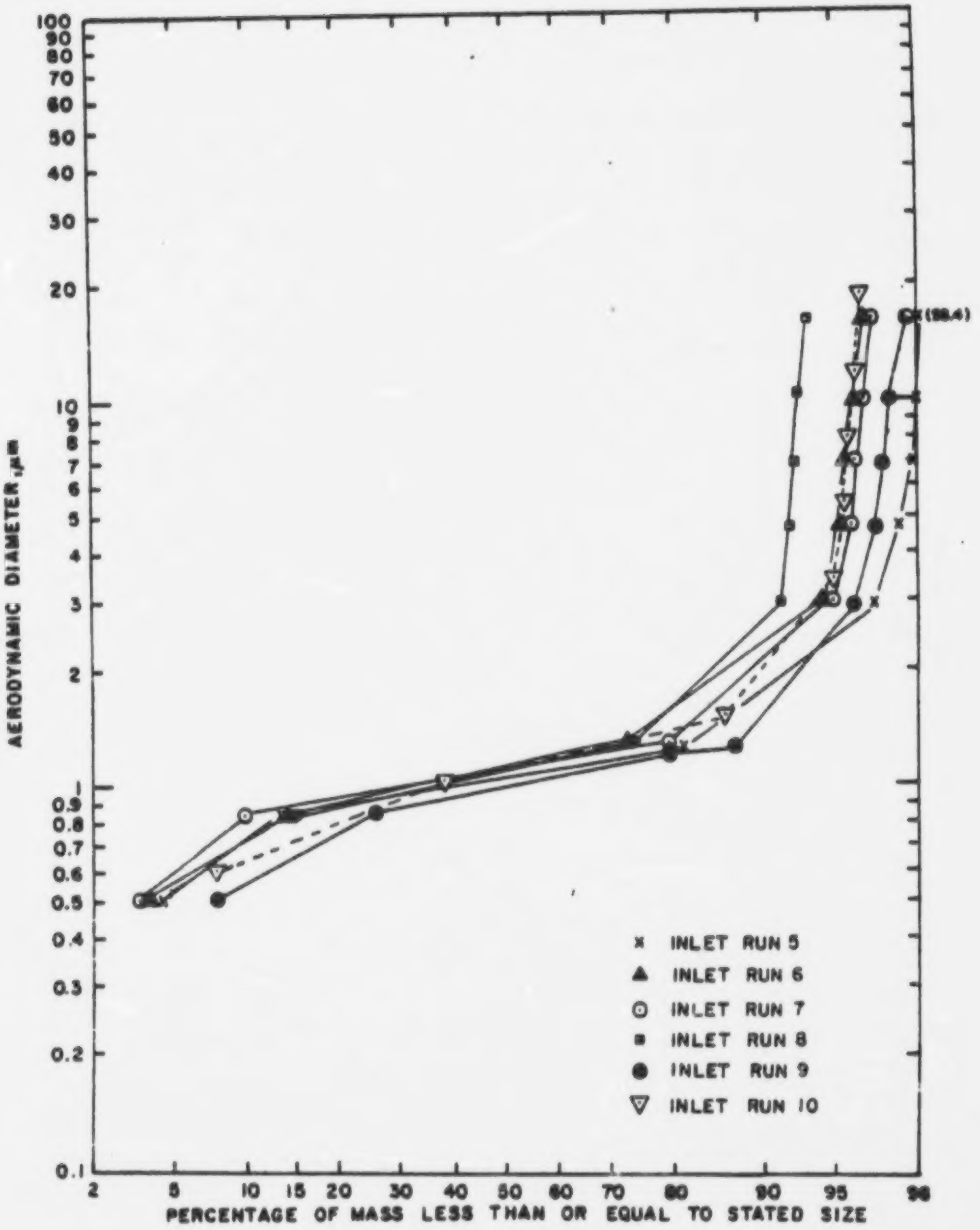

Figure 3.12Fractional size distribution of EFB unit

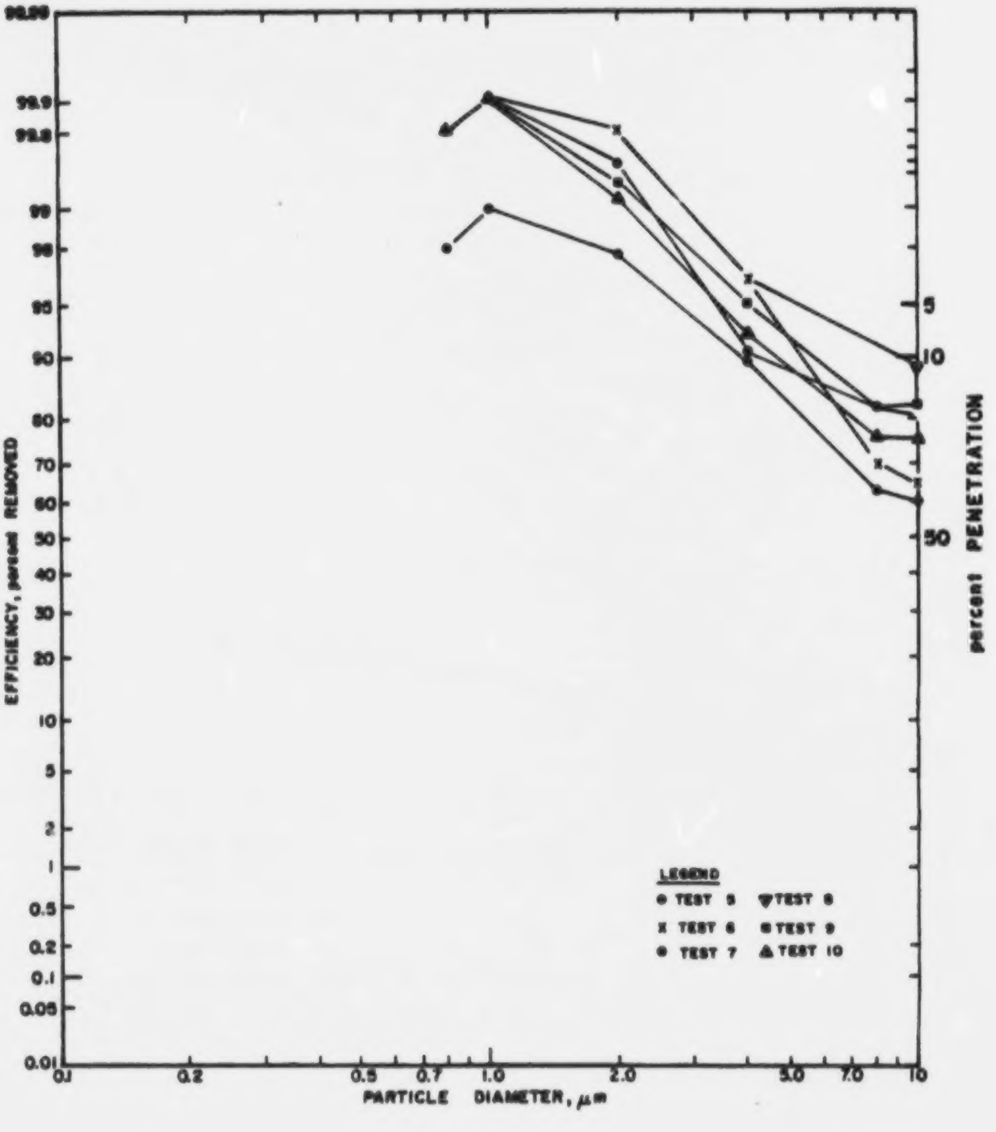

Figure 3.13 Fractional efficiencies of EFB unit as measured with Andersen impactor.

is allowed to drain to barrels below the system. Collected oil is subsequently used as boiler fuel. The system is of compact size for a submicron particulate control device as can be judged from the accompanying photograph. EFB, Inc. has been awarded a patent which covers several of the innovations of this technology [26].

The EPA has conducted a test program to evaluate the application of the EFB, Inc. system to the roofing problem [27]. Figure 3.12 shows the inlet particle size distribution observed during the EPA tests. Note that the particle size is primarily below 1 μm. Figure 3.13 shows the fractional efficiency of the unit as a function of particle size. For particles of 1 μm in size four of the five tests show a collection efficiency of 99.97. The lower efficiences observed for larger particle sizes where little material exists is not explained by the theoretical collection theory. In fact, the theoretical collection efficiency should increase for the larger particle sizes. This anomaly can be explained by electrostatic effects in the cascade impactors [28], weighing errors at these low loadings, or material bleedthrough from the particle beds.

Louvered beds have long been proposed for the collection of not only flyash, but also SO_2. [29,30,31]. Dry additives can be injected into the gas stream and collected on the surface of the panel bed. Good mass transfer is achieved, and the spent reagent is removed with the ash as the bed is rotated. Spray dryers have recently been proposed for injecting reagent into the flue gas [32]. Spray dryers inject material in a slurry form. As the particles travel downstream they dry, and a fine particulate of reagent is eventually collected downstream. The injection of particulate in a wet form is desirable, since wet films can significantly enhance reactions between

SO_2 and alkali reagents. The downstream collection system should keep material exposed to the flue gas stream to enhance utilization, since the residence time of ductwork between the spray dryer injection and downstream collection system is typically not large enough. Consequently a baghouse has been proposed for this job by American Air Filter and many other companies.

The significant innovation introduced by the spray dryer is the potential utilization of calcium based materials. Previous forms proposed for dry scrubbing have relied on the more reactive sodium based materials. Sodium based materials are both water soluble and expensive, although an ion exchange can be employed in a separate reactor vessel. The Electrified Bed offers a mass transfer system which can compete with a baghouse for combined SO_2 collection and high efficiency particulate control. The development of the calcium based process should enhance interest in dry SO_2 collection.

The separation of flyash from Electrified Bed granules is a critical step in system operations. This separation has been successfully achieved in a small auxiliary fluidized bed, with the ash agglomerates entrained in a gas stream significantly smaller than the primary stream. During the GM test, the secondary gas stream flowrate ranged from 3% to 5% of the primary gas flow. Secondary air stays in a low temperature range ideal for the use of a fabric filter bin vent. Figure 3.14 shows the particle regeneration system used at GM in block diagram form.

Since large panel beds have already been employed in industrial processes, development questions primarily are concerned with the air pollution adaptations and the relative economics of this technology, scaled up versus present conventional technology. The economics of the particle regeneration system

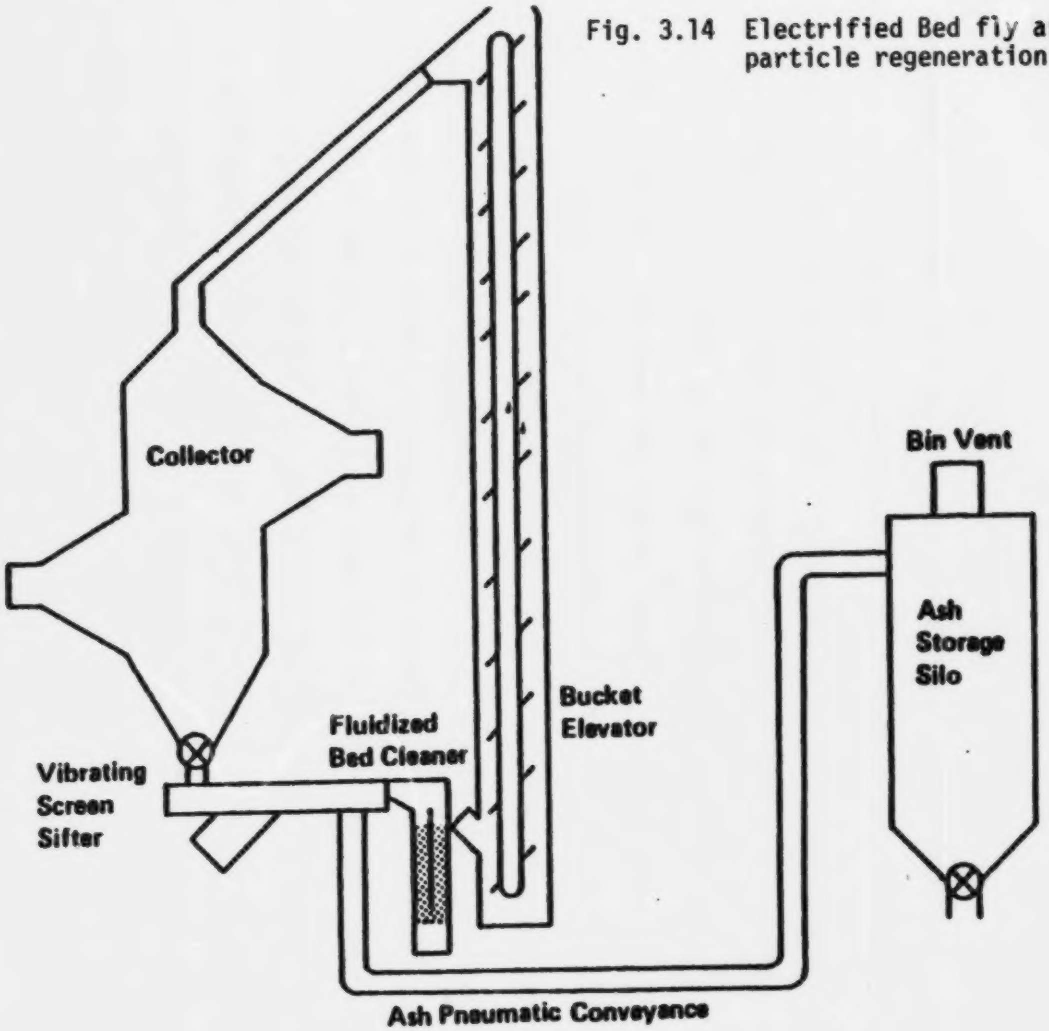
Collector
Vibrating
Screen
Sifter
Fluidized
Bed Cleaner
Bucket
Elevator
Bin Vent
Ash
Storage
Silo
Ash Pneumatic Conveyance

Fig. 3.14 Electrified Bed fly ash collector particle regeneration system.

and louvered construction cannot be accurately determined without a scaleup of the system to the 10,000 cfm (5 m^3/sec) level. Presently EFB, Inc. is quoting a hardware price of \$2.50/cfm for the entire system, including the regeneration section.

3. Outline of Inherent Characteristics

The Electrified Bed system offers 99% submicron efficiency with a pressure drop of under 5" W.G. Collection efficiency is not dependent on ash resistivity, and by using glass cullet as a bed material, operation can continue with high levels of boiler carbon emission. System pressure drop is dominated by the fixed particle bed, so scaleup is straightforward and similar to baghouse scaleup. Boiler turndown only serves to decrease system pressure drop and increase system efficiency. A two-stage Electrified Bed can be purchased for roughly \$2.00/cfm, whereas a one-stage Electrified Bed should be purchasable for half that amount. (1980 dollars).

Standard construction techniques are sufficient for the Electrified Bed collector, with most of the wear occurring on the bed louver sections. After several years of operation louvers can be unbolted and easily replaced.

In the retrofit mode the one-stage Electrified Bed requires a minimum of electrical service, only that which is required to impose a static electric field across the sand bed. This requirement will typically be 0.2 watts/acfm.

D. High Intensity Ionizer

1. General Description

The high intensity ionizer is a device designed to impart a high electric charge to flyash before it enters an electrostatic precipitator (ESP). Although an electrostatic precipitator is designed to both charge and collect particulate, certain advantages can be achieved by utilizing the high intensity ionizer (HII).

1. The geometry and high gas velocities in the HII permit the use of electric fields typically three times higher than those utilized in a conventional ESP.
2. The small anode area utilized permits the use of bleed air to keep the region clear of collected ash. The resistivity of collected ash can cause back corona and a limitation on the potential operating current densities. Bleed air is also utilized around the cathode.

The high intensity ionizer, originally developed by Air Pollution Systems has undergone development over the last few years with EPRI sponsorship, and is currently being marketed by the Environmental Systems Division of Union Carbide Corp. (Union Carbide has recently announced that it will sell off the HII technology by the end of June, 1979.) Frank Small, Product Manager in the Particulate Air Pollution Control Division of Union Carbide has offered to assist the New England Utilities study with design data for particular retrofit applications [33].

The motivation for retrofitting with the high intensity ionizer stems from the problems encountered with particle charging when burning low sulfur coals. Flyash conductivity is usually tempered by an adsorbed layer of SO_3 which provides for ionic conduction. When low sulfur coals are utilized (less than 1% S) the amount of SO_3 present is minimal and the incipience of back corona sets an upper limit on the permitted ESP field strength and associated ion current. In addition, high resistivity dust is difficult to rap because of the strong electrostatic force pinning it to the wall. This results in greater reentrainment problems.

As a result, ESPs designed for high resistivity ash must be designed much larger to achieve the same collection efficiency. In an EPRI sponsored study, manufacturers were polled concerning the size precipitator they would specify to achieve 99.5% collection on a 700-MW power plant burning both low and high sulfur coal. [34] Table 3.4 shows the responses of the manufacturers. Note the significantly larger size of the systems for low sulfur coal and the corresponding lower effective drift velocities. From this data 4 cm/sec was determined to be a typical drift velocity for a precipitator operating on low sulfur coal. The EPRI study shows that with the use of the HII this effective drift velocity can be boosted to at least 8 cm/sec, effectively cutting in half the necessary active precipitator volume to achieve a particular efficiency.

Physically, the HII consists of an array of venturi throats arranged in parallel. Figure 3.15 illustrates the HII installed at the inlet to a conventional electrostatic precipitator. Although the velocity in the ionizer

REFER TO

TABLE 3.4

TABLE 3.4

Cost and size data for conventional electrostatic precipitators from four vendors to yield 99.5% efficiency on both high and low sulfur coal.

COAL	UNITS	VENDORS			
		A	B	C	D
High Sulfur Coal (2.5 - 3.5% Sulfur by Weight)					
Cost, installed	10^6 \$	5.60	5.98	3.63	10.4
Plate area	10^6 ft^2	0.600	0.598	0.490	0.672
Plate area to flow	$ft^2/ft^3/min$	0.300	0.299	0.245	0.336
Drift velocity	ft/min	17.7	17.7	21.6	15.8
Drift velocity	cm/s	8.97	9.0	11.0	8.00
Cost/ft^2 collecting area*	\$/ft^2	9.33	10.0	7.4	15.4
Low Sulfur Coal (0.5 - 1.0% Sulfur by Weight)					
Cost, installed	10^6 \$	17.5	9.90	10.2	16.6
Plate area	10^6 ft^2	2.80	1.10	1.34	1.13
Plate area to flow	$ft^2/ft^3/min$	1.400	0.549	0.670	0.567
Drift velocity	ft/min	3.78	9.65	7.91	9.35
Drift velocity	cm/s	1.92	4.9	4.02	4.75
Cost/ft^2 collecting area*	\$/ft^2	6.25	9.0	7.6	14.7

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*Data supplied or derived from data supplied by precipitator vendors.

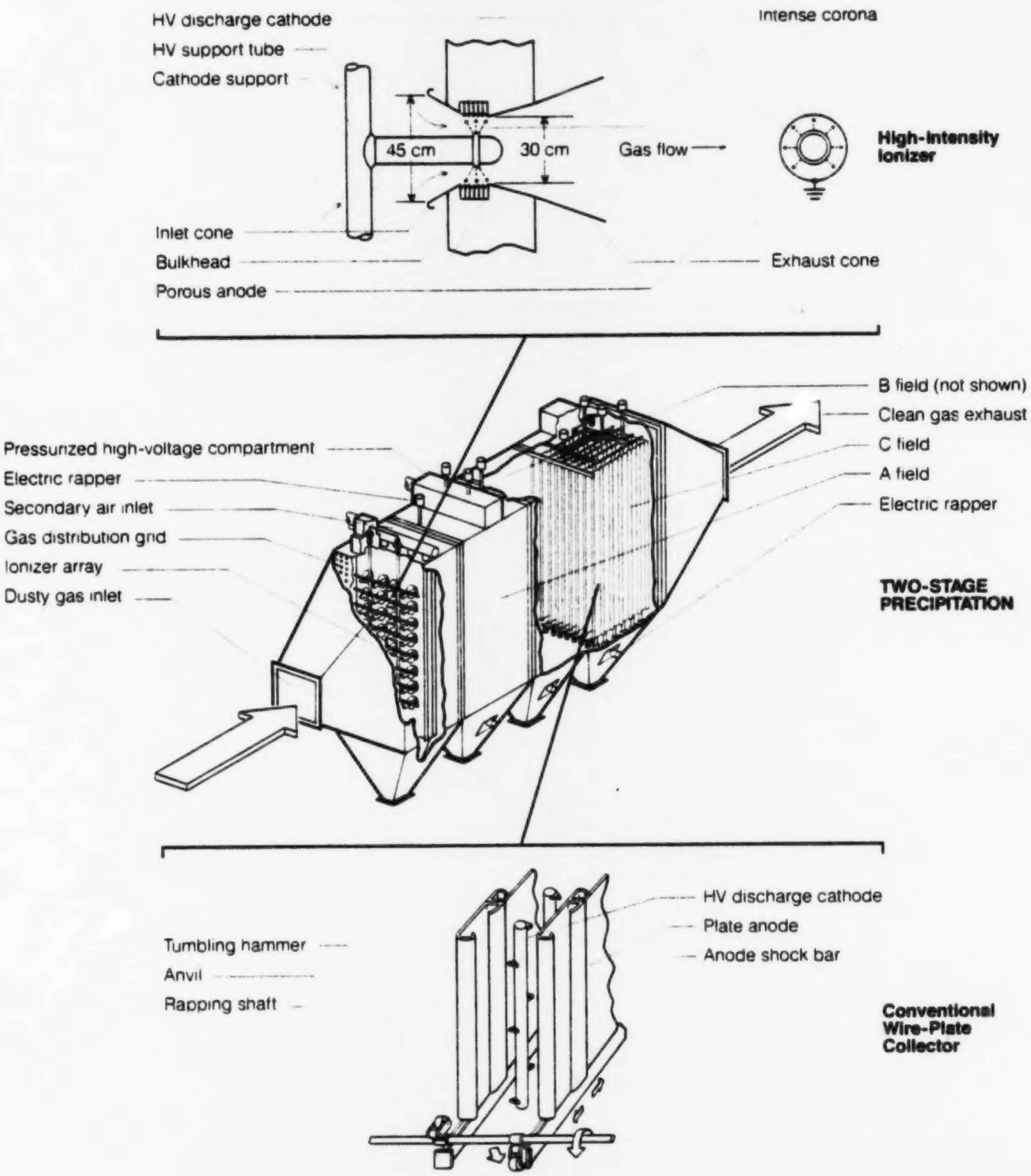

HV discharge cathode
Intense corona
HV support tube
Cathode support
45 cm
30 cm
Gas flow
High-intensity Ionizer
Inlet cone
Bulkhead
Exhaust cone
Porous anode
B field (not shown)
Clean gas exhaust
Pressurized high-voltage compartment
C field
Electric rapper
A field
Secondary air inlet
Electric rapper
Gas distribution grid
Ionizer array
Dusty gas inlet
TWO-STAGE PRECIPITATION
HV discharge cathode
Plate anode
Tumbling hammer
Anode shock bar
Anvil
Rapping shaft
Conventional Wire-Plate Collector

Fig. 3.15 High intensity ionizer single element and two-stage precipitator drawing.

throat is as high as 25 m/sec, the venturi design will keep overall system pressure drop down to 1/2" W.G. The HII can be used in both a new installation and ESP retrofit mode. An EPRI sponsored economic analysis projects that the device, complete with 196 throats and sufficient for handling 250,000 cfm, will sell for $150,000 in 1976 dollars [35].

Although the theory of the HII suggests that an improvement in performance will result from its use on the emissions from high sulfur oil, the studies provided do not indicate what that improvement might be. Effects of reentrainment, bypass, and space charge effects create uncertainty as to the resulting HII performance on a full-scale application. With the ionizer attached to a conventional ESP, the EPRI study states, "It is anticipated that the collector ESP will be somewhat smaller than a competitive ESP under normal resistivity conditions, and considerably smaller than the competitive ESP under high resistivity conditions." [36]

2. State-of-the-art, Development Requirements

An ESP collecting coal emissions will typically operate at electric field strengths of from 2.5 - 3.5 kV/cm and ion current densities of from 30 - 60 nA/cm^2 [37]. The high intensity ionizer operates at a field intensity of 12 kV/cm and an ion current density of 600 nA/cm^2 [38]. The EPRI Journal reports that on 0.8% S coal the high intensity ionizer reliably operated at 10.8 kV/cm and 6330 nA/cm^2 while the ESP following the high intensity ionizer operated at 3.3 kV/cm and a current density of 13 nA/cm^2. The ratio of high intensity ionizer charge to that achieved in a conventional ESP is shown in Figure 3.16. Figure 3.17, taken from the EPRI research report, shows a four throat laboratory HII [39].

The two-stage ESP concept was first developed by G. Penney in the 1930s for Westinghouse. This early "precipitron" is the forerunner of

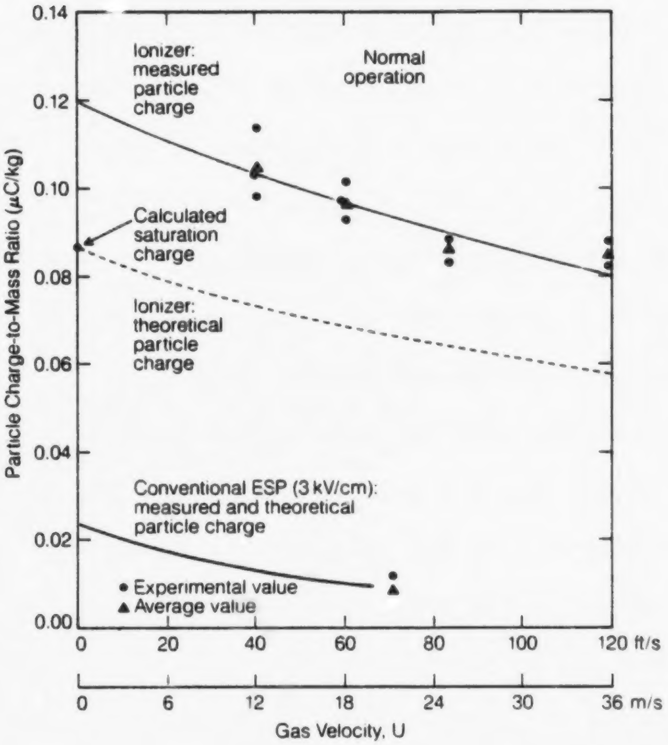


Fig. 3.16 Particle charge as a function of gas flowrate for the high intensity ionizer and a conventional electrostatic precipitator.

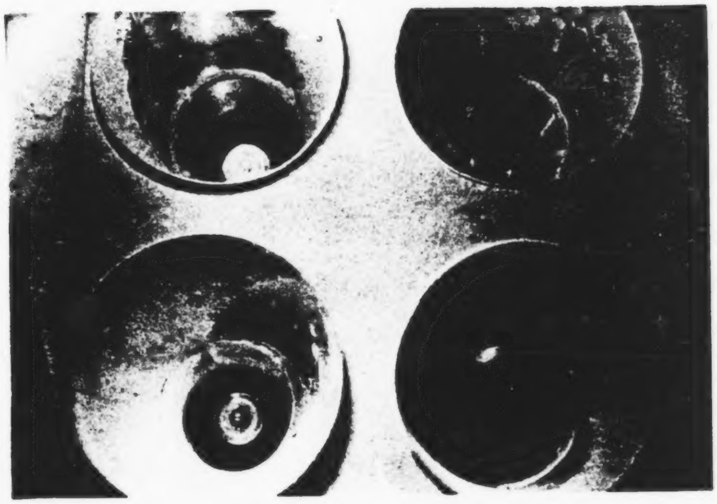


Fig. 3.17 Downstream view of four throat laboratory high intensity ionizer array.

two-stage collectors which are currently in service on shop air, welding smoke, and restaurant-type applications. This concept was not utilized for the flyash application because of the necessity to recharge dry material which can blow off or bounce off of electrode surfaces. Whereas in the shop air application two-stage collection allows the collector electrodes to be closely spaced, this advantage is not achieved in the flyash application where emitting wires are still necessary in the collection region. Today, with the increase in usage of low sulfur coal, this concept is being reexamined with the sponsorship of EPRI. Frank Small of Union Carbide reports that the high intensity ionizer should be considered for applications with coal sulfur content as high as 1 1/2% [40]. Features of the high intensity ionizer can be summarized:

1. The device is small and easily retrofitted to the inlet section of most ESPs. Although the venturi throat velocity of as high as 30 m/sec will cause system pressure drop, this effect is reduced by the removal of flow straightening screens which are no longer required. Literature provided on the HII by EPRI indicates a system pressure drop of 1/4" W.G. A nominal power consumption of .06 watt/acfm is reported for the device [41].

2. The high intensity ionizer achieves a high particle charge before particulate enters the ESP. Better utilization of the ESP is achieved on low sulfur coal since charge can only be added slowly with conventional charging techniques.

3. The geometry and high gas velocities in the HII allow high electric field strengths to be utilized. High gas velocities serve to extinguish streamers which precede corona breakdown. Figure 3.18 shows typical I-V characteristics for the HII and an ESP. Present plans call for the HII to

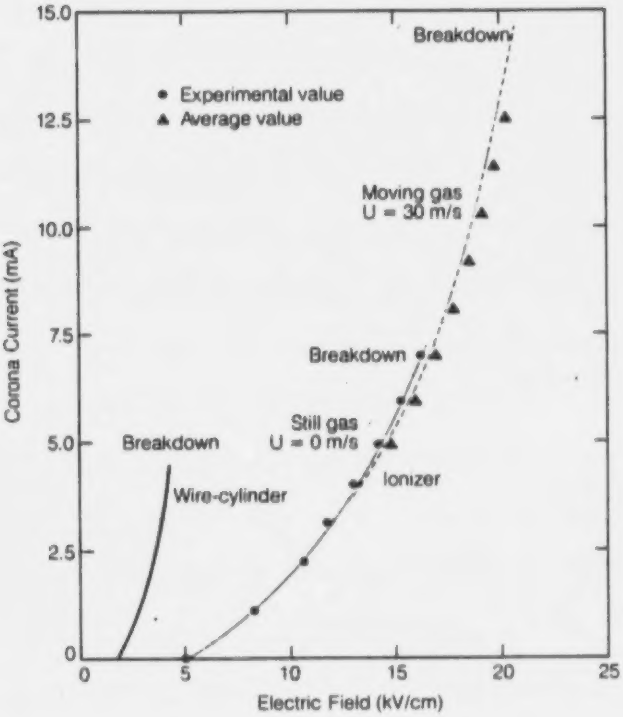


Fig. 3.18 Corona V-I characteristic for high intensity ionizer as a function of gas flow compared to a conventional charging wire.

run at 12 kV/cm. Promoters hope to eventually be able to operate the device at 20 kV/cm. An important aspect of HII operation is the small anode area utilized, which facilitates intensive cleaning techniques which would not be practical across the volume of an ESP. The HII uses .08 $m^2/(m^3/sec)$ of anode area to charge the gas stream, which is two to three order of magnitude less than that employed in an ESP. This anode area must be kept free from resistive coatings of flyash to prevent back corona sparking from occurring. Built up flyash particles create field irregularities which pose severe problems for HII operation because of the small gap and high field strengths utilized. In response to these problems the HII anodes are porous and are manifolded to a clean air supply out of the active volume. Bleed air is forced in at a rate of 6% of the primary flue stream. Various experiments have been conducted by heating, cooling, adding steam, and adding SO_3 to the bleed air supply. Test results on a 35,000 acfm scale at Arapahoe shown that with the use of bleed air ash buildup on the anode is not a problem in ionizer operation [41].

The first field tests of the HII were performed on the John Sevier Steam Plant of the TVA. Between 2000 and 3000 cfm of gas was treated with coal sulfur content ranging from between 0.8%S and 3.0%S. A slipstream was tapped from after the plant's multiclone. The reduction in output loading resulting from switching on the HII ranged from 55% with high sulfur coal to 70% with low sulfur coal. The EPRI research report states, "A greater reduction in penetration averaging 70% was measured in this series of tests, partially due to higher corona currents (SO_2 tends to quench corona). However, the main reason for the greater improvement is thought to be the reduction in reentrainment losses from excessive rapping in the precipitator during high sulfur testing." [42]

The HII following by a 7.4 sec residence time ESP was tested on a 35,000 cfm slipstream at the EPRI test facility in Arapahoe [41]. Coal of 0.74% S and 14% ash was utilized. During the test program it was determined that a multiclone must be utilized before the HII to reduce the high space charge effects which were reducing performance.

It was also determined that high space charge levels after the HII and at the inlet to the ESP can induce positive corona off the edge of the ESP collecting electrodes and subsequent charge cancellation. An electrical shield was emplcyed which covered the sharp edge of the collecting electrode. A reduction in optical density of 55 - 60% is reported after switching on the HII. Tests of the effect on mass loading and size distribution are not reported.

The effectiveness of the HII can be judged with the assistance of the particle charging expressions for field charge and diffusion charge. Equation 3.1 expresses the saturation field charge for a conducting or highly dielectric particles. The time constant by which this saturation charge is achieved is expressed by Eq. 3.2. This time constant can be derived by equating the saturation charge with the current flux density in the charging region. Equation 3.3 presents White's model for diffusion charge, which is characterized by the product $n_i t_c$ [43]. The ion density can be approximated by Eq. 3.4.

$$q = 12\pi\varepsilon_o E R^2 \qquad (3.1)$$

$$\tau_e = \frac{4\varepsilon_o E}{J} \qquad (3.2)$$

$$q = \frac{4\pi\varepsilon_0 RkT}{e} \quad \ell n \left| 1 + \frac{R\bar{V}n_i e^2 t_c}{4\varepsilon_0 kT} \right| \tag{3.3}$$

$V \equiv$ ion RMS velocity

$t_c \equiv$ charging time

$k \equiv$ Boltzmann's constant

$$n_i = \frac{J}{eb_i E} \tag{3.4}$$

$b_i \equiv$ ion mobility

$n_i \equiv$ ion density

Field charging parameters are reported in Table 3.5 for the HII, the Mystic 7 precipitator, and typical parameters for a moderately sized precipitator operating on high resistivity ash.

TABLE 3.5
FIELD CHARGING PARAMETERS

Device	$E(\frac{kV}{cm})$	$J(\frac{nA}{cm^2})$	τ_c(msec)	τ_{inf}(msec)
HII	11	6330	0.6	3.8
Mystic 7	3	53	23	7700
ESP (high resistivity ash)	3	13	90	3000

The field charging parameters reported in Table 3.5 reveal that a significantly higher saturation field charge can be achieved in the HII compared to an ESP. Although the pollutant residence time in the charging region of this device is only 3.8 msec, this is a sufficient period for effective charging due to the short charging time of 0.6 msec. Note also that in the ESP charging time is very small compared to gas influence time. Even for typical ESP parameters on high resistivity dust, charging time is small compared to the influence time. This analysis helps to indicate that the difficulties associated with resistive ash can not be attributed to field charging time.

The HII does not significantly contribute to the diffusion charging of particulate. This can be determined by comparison of the characteristic products $n_i t_c$ as shown in Table 3.6.

TABLE 3.6

Diffusion Charging Product

Device	$n_i t_c$ (sec/m^3)
HII	6.3×10^{12}
Mystic 7	3.9×10^{14}
ESP (high resistivity ash)	3.7×10^{13}

Diffusion charging is important for the collection of fine particulates, particularly below 0.5μm. Collection in this size range becomes important as emission standards become tighter.

Charging processes are also influenced by space charge quenching effects. The magnitude of the space charge problem for both the HII and the conventional ESP was determined through a numerical computation in which the product of the lognormal size distribution which characterizes coal emissions and the field charging equation was integrated throughout the particle size range for a typical coal emission. Coal of 10% ash and 13,000 Btu/lb was chosen.

A boiler ash retention of 20% is assumed. The space charge in a gas charged to saturation can be determined through evaluation of Eq. 3.5.

$$Q(\frac{\mathrm{coul}}{m^3}) = \int_{d=0}^{d=\infty} 12\pi\varepsilon E R^2 \; f(d) \; \frac{1}{\frac{4}{3}\pi R^3 \rho} \; M(\frac{\mathrm{gm}}{m^3}) \; d(d) \qquad (3.5)$$

$$f(d) = \frac{1}{\sqrt{2\pi}\,\log \sigma_g} \; \exp[\frac{-(\log d - \log d_g)^2}{2 \log^2 \sigma_g}] \; \frac{1}{2.303 d} \qquad (3.6)$$

$M(\frac{\mathrm{gm}}{m^3}) \equiv$ gas total mass loading

$d_g \equiv$ mass median diameter

$\sigma_g \equiv$ geometric standard deviation

The gas mass loading can be determined from the fuel ultimate analysis and the boiler excess air rate. Methodology for this conversion is discussed in an appendix. Table 3.7 presents the parameters used for this calculation. Typical size distribution from before and after a multiclone was taken from "A Manual of Electrostatic Precipitator Technology." [44] The calculation was performed for an ESP and the HII, both before and after a multiclone. Although the multiclone collected 70% of the total mass, larger particles are characterized by a smaller charge to mass ratio and the total space charge level was only reduced by 42%. The results of these calculations are presented in Table 3.8.

The significance of these numbers can be determined by comparing the self field of the airborne particles with the imposed field in the device. The formula which describes the electric field between parallel plates with

TABLE 3.7

Space Charge Calculation Parameters

E for ESP	2.9×10^5 V/m
E for HII	1.2×10^6 V/m
M without multiclone	3.69 gm/m^3
d_g without multiclone	13 μm
σ_g without multiclone	3.4
M after multiclone	1.11 gm/m^3
d_g after multiclone	4.3 μm
σ_g after multiclone	2.6

TABLE 3.8

Space Charge in ESP and HII

Inlet of ESP without multiclone	2.7×10^{-5} $coul/m^3$
Inlet of ESP with multiclone	1.9×10^{-5} $coul/m^3$
HII without multiclone	1.1×10^{-4} $coul/m^3$
HII with multiclone	7.8×10^{-5} $coul/m^3$

an imposed voltage and uniform distributed space charge is shown by Eq. 3.7.

$$e = v/\ell + Q/\varepsilon(x - \frac{\ell}{2}) \qquad (3.7)$$

$x \equiv$ distance measured from ion emitting plane

$\ell \equiv$ plane spacing

A criterion for the influence of space charge is the ratio of the space charge field at the emitting plane $Q\ell/(2\varepsilon)$, to the imposed field, V/ℓ. This data for the HII and on ESP is shown in Table 3.9.

TABLE 3.9

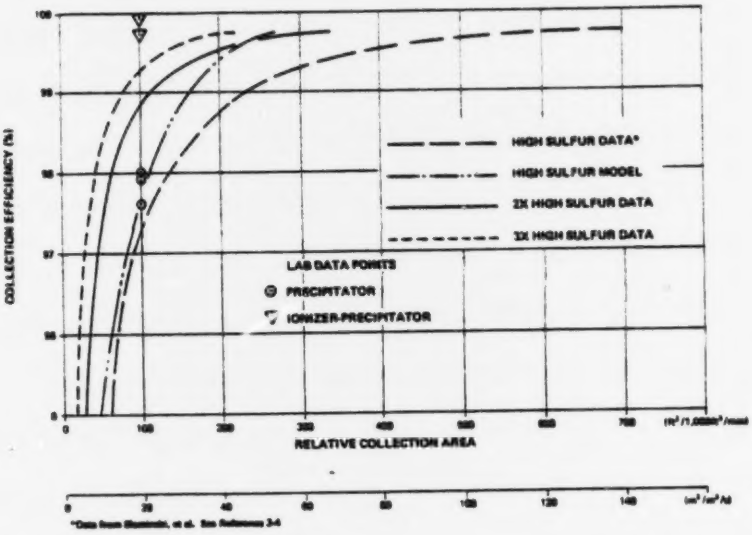
Comparison of Induced to Imposed Field Without Multiclone

	HII	ESP
Induce field $\frac{Q\ell}{2\varepsilon}$ $(\frac{V}{m})$	5.5×10^5	1.9×10^5
Imposed Field $\frac{V}{\ell}$ $(\frac{V}{m})$	1.2×10^6	2.9×10^5
Ratio of induced field to imposed field	.46	.66

This calculation shows that space charge can have a deleterious effect on charging in both the HII and an ESP. The HII can impart a significantly larger charge than the ESP because of the higher field strengths employed. In addition, its geometry helps to reduce space charge problems. A multiclone can reduce the blockage of field due to space charge by roughly 40%.

Although the ESP is initially more space charge limited than the HII, the collection occurring as gas continues down the device helps to reduce this effect, and consequently particles in an ESP can gradually receive a greater charge. Promoters of the HII have recommended that the device either be preceded by a multiclone or placed in the middle of an ESP. Union-Carbide personnel have suggested that for some installations a section of the second ESP field can be replaced by the HII with a significant overall improvement in ESP performance [45]. Tests performed with the HII at both the John Sevier station of the TVA and at Arapahoe utilized a multiclone before the device, and at Arapahoe deleterious downstream electrical effects occurred without the multiclone. These effects were reduced through the use of electrical shields which served to take the strong space charge fields off the leading edge of the ESP collecting electrodes. This strong field occurred in the space between the HII and the following ESP.

To understand the utility of the HII it is necessary to examine the characteristics which limit the performance of an ESP. Both the HII and an ESP provide more than an order of magnitude more current to corona than is convected downstream on particles for typical coal emissions. This fact can be deduced for the HII from the data in Table 3.8 and the 5 ma/m^3/sec current level utilized in the device. ESP efficiencies are characterized by the Deutsch equation with factors causing deviations from this theory both up and down. Figure 3.19 shows a comparison between calculated and observed ESP efficiency for use on high sulfur coal [46]. Reentrainment, poor gas flow distribution, and sneakage contribute to bringing the observed efficiency somewhat below the predicted. On the other hand, diffusional charging (not included in this calculation), enhanced charging due to particulate passing in the vicinity of a wire (electric fields are typically twice the average value in this region [47]), and laminar flow characteristics help to counteract negative deviations and keep the observed efficiencies quite close to



*Data from [illegible], et al. See Reference 3-4

Fig. 3.19 Data points and anticipated performance for high intensity ionizer on high sulfur coal.

those predicted from the simple theories.

On the other hand, high resistivity ash displays a collection efficiency much lower than that predicted by the simple Deutsch theory. Table 3.4 shows that the effective drift velocity claimed by manufacturers for high resistivity ash is on the average a factor of 2.73 less than the drift velocity claimed for low resistivity ash. This factor is not accounted for by the ratio of the theoretical drift velocities for the two applications. Theoretical drift velocity in a conventional ESP is proportional to E^2. The EPRI report claims that an electric field of 4 kV/cm can be used on high sulfur coal while only 3 kV/cm can be used on low sulfur coal [48]. The ratio of E^2 for these two cases is 1.8, which is lower than the 2.73 manufacturer's reduction. Careful ESP design would not require any reduction in electric field for high resistivity ash, since back corona is caused by too high of a current density rather than too high of an applied voltage. For a particular wire size current and voltage are exponentially related, but larger wires can be employed which would serve to reduce current at a particular voltage. In fact, promoters of the HII recommend that larger wires be employed in an ESP which employs the HII [49]. Table 3.5 shows that lowering the ESP current density but not the voltage will have a very minimal effect on field charging. Table 3.6 shows that the lower current density has a more significant effect on diffusional charging. A significant factor affecting the collection of high resistivity ash is the difficulty associated with rapping when imposed currents pin the ash tightly to the ESP plates. Vigorous rapping is required to dislodge this material, and consequently more reentrainment results. Lower current densities are helpful in reducing the electric force pinning the ash to the wall. Other effects reducing ESP performance, such as space charge quenching, are problems which equally affect high and low resistivity ash.

In summary, the problems which make the collection of high resistivity ash more difficulty than low resistivity are:

1. Rapping difficulties
2. Less diffusion charging
3. A lower electric field to drive migration
4. A lower electric field to effect field changing

Problem 2 cannot be solved by either larger wires or the HII. Problem 3 and to an extent Problem 1 can be solved only through the use of larger wires, but an even larger charging field than is possible in an ESP can be provided by the HII. Note that the advantage of the HII for point 4 applies to the same degree to all ESPs, regardless of ash resistivity. High charging only at the inlet to an ESP may not show as much of an improvement in efficiency as expected. A study by EPRI concludes [50]:

> It is anticipated that since the high intensity ionizer arrangement may not be able to reprecipitate dust as effectively as a conventional precipitator when plates are wrapped, the overall effect of rapping may be more deleterious in a high intensity ionizer-precipitator than in a conventional precipitator. However, it may be possible to operate the high intensity ionizer precipitating section at low current levels, maintain a high precipitating field strength, and rap less intensely to reduce reentrainment. These effects can only be analyzed effectively in future tests.

This quote effectively outlines the most important unknown concerning the HII. The HII claims to be able to charge particles with a field three times higher than that used in a conventional ESP. Promoters of the device claim that field charging theory underestimates the charge achieved in the HII by 40% [51]. This effect is attributed to free electron charging, which reportedly occurs with the use of electric fields near breakdown. This enhancement in practice serves to increase the particle charge up to the saturation level, counteracting the short HII residence time. It is unknown how effective an enhanced one-time charge will be in practice. The effect can be to reduce ESP size by from a factor of three to not at all, depending on the relative importance of loss of charge (perhaps through induced corona effects), reentrainment, diffusional charge, and other effects.

Union Carbide, promoters of the HII claim that the device in the aggregate will serve to reduce ESP size by a factor of two. Figure 3.19 shows the effect of a reduction in ESP size by a factor of two and three for high sulfur coal with experimental points and Fig. 3.20 shows these same effects for low sulfur coal [52].

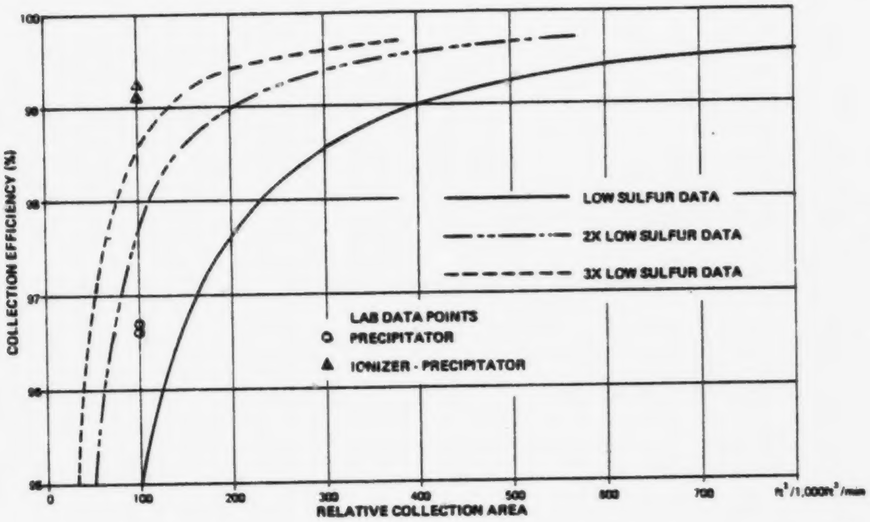


Fig. 3.20 Data points and anticipated performance for high intensity ionizer on low sulfur coal.

This reduction effect has been demonstrated during the John Sevier and Arapahoe pilot scale tests on ESPs supplied specifically for demonstration purposes. The first full-scale HII will go in service sometime this summer on the Shawnee plant of the TVA [45]. This installation will consist of 90 ionizer throats, and is being supplied by Air Pollution Systems.

According to Dr. Chang of Union Carbide the HII provides a factor of two advantage for both high and low resistivity ash, with a greater utility realized on the high resistivity ash because of the larger ESP utilized. This relationship should not hold in practice because of the four problems listed with respect to the collection of high resitivity ash, only the fourth is addressed by the HII. Problem 1 specifically is addressed to the need for recharging highly resistive ash as this material is more frequently reentrained. A significant improvement should be realized by increasing electric field strength in these units through the use of larger wires.

The significance of a one-time charge can be surmised from the data in Fig. 3.19 and Table 3.4. Note that in Fig. 3.19 the collection efficiency data falls below the model only at higher efficiency levels, where reentrainment and other secondary effects serve to bring down the efficiency. One-time charging would appear to be effective up to the efficiency where these two curves separate, and the factor of two seems reasonable. The separation of the curves is a testimonial to non-ideal effects which the HII does not directly address. From Table 3.4 it can be observed that on high resistivity ash the effective drift velocity is reduced on the average by a factor of 2.73 below low resistivity. Of this reduction, a factor of 1.8 can be accounted for by the lower fields utilized in ESP used on the highly resistive ash, and this factor can be recovered by utilizing larger wires. The rest of the factor of 2.73 can not be recovered either through the use of larger wires or the HII, but perhaps can be modified through other improvements in operating procedures. Of the 80% factor which is recoverable through the use of different wires, the root or 33% is due to the impact of the lower electric field on charging. This is equivalent to saying that only 33% of the extra box size can be accounted for by the effect of the lower electric field on charging. The conditions which require an additional 140% of active volume are not addressed by the employment of the HII. Let us assume for the sake of argument that we still require an ESP of 140% nominal size for highly resistive ash, but reduce the size of the other 133% component by a factor of from two to three. This should be interpreted as a liberal way to estimate the overall effectiveness of the HII, especially for higher efficiencies. This analysis shows that the effect of the HII is to reduce overall box size by a factor of from 25% to 33%. Even this factor could prove to be cost effective considering the enormous size of high efficiency ESPs. In addition, this advantage is achieved in only 4' - 6' of treatment length in the direction of flow, an important consideration for space limited retrofit applications.

Steve Zahos of Union Carbide visited MIT to supply information on the HII development [45]. Union Carbide has designed a standard HII model with a 12" throat size (see Figure 3.15). These throats have a rated capacity of 3500 cfm each, and are spaced with 3' centers. The rating of 3500 cfm is based on an upper limit of 75 fps (23m/sec) throat velocity for effective operation. Consequently, ESPs with facial velocities of above 389 fpm (2 m/sec) are poor candidates for employment of the HII. The employment of 3' centers leaves only 6" of spacing between venturi expander sections.

The data supplied in the EPRI study on HII cost can still be employed today, according to Mr. Zahos. Table 3.10 shows the HII cost as reported in that study [35]. An economic analysis was performed under the sponsorship of EPRI to determine the cost savings associated with use of the HII [53]. In the study installations are retrofitted to be capable of achieving 99.5% efficiency with low sulfur coal. Flue gas volume is set at 2 million cfm, 325°F, and 7% moisture representing a nominal 700MW coal burning installation. The results of this evaluation are presented in Table 3.11 along with a description of the four cases considered. Estimates from two engineering organizations are reported. Enviro Energy owns Air Pollution Systems and is a promoter of the HII development. Calculations in the study are based on the factor of two improvement in effective ESP drift velocity already discussed.

Table 3.10

ESTIMATED COST - IONIZER ARRAY

(ONE CHAMBER 196 - 8 in. IONIZERS 250,000 actual ft^3/min)

ITEM	COST ($)	COST PER CHAMBER ($)
Ionizer Array - Anode, Disc, Air Diff.	23,520	
Front Plate and Back Plate	22,200	
Pipe, Crosses, Caps	1,800	
Melamine	200	
TOTAL - Array		$ 47,720
High-Voltage Assembly		
Support and Guide Frames	4,000	
Insulators	540	
Stabilizers	2,000	
Attachments and Hardware	500	
TOTAL - High Voltage		7,040
Rapping Devices		
System	150	
Airlines and Solenoid Valves	400	
Air Hose	250	
Pressure Regulator & Lub. Filter	200	
TOTAL - Rapping		1,000
Transformer & Controls		
Transformer and Control	10,000	
Bus Duct and Fitting	900	
Transformer Bushing Housing	200	
Inlet Bushing	200	
Disconnect Switch Housing	350	
Insulator Compartment	2,000	
Shrouds	1,000	
TOTAL - Transformer & Controls		14,650
Air Shield		
Fan, Drive, Heater	4,000	4,000
Rapper Control Panel	4,000	4,000
Safety, Signs, Horns, Interlock	300	300
TOTAL Direct Material		$ 78,710
Direct Cost		$100,000
New or Retrofit Material Selling Price with Contingency		$150,000
Retrofit Construction with Contingency		$150,000
New Construction with Contingency		$ 75,000
Total Retrofit		$300,000
Total New		$225,000

Table 3.11

ESTIMATED CAPITAL COSTS AND COST SAVINGS USING THE HIGH INTENSITY IONIZER

	ESTIMATES (10^6 $)	
	Kaiser Engineers	Enviro Energy
CASE I - NEW INSTALLATION		
Conventional	13.6	11.5
With High Intensity Ionizer	9.8	8.0
Savings	3.8 (28%)	3.50 (30%)
CASE 2 - RETROFIT INSTALLATION		
(Originally, 99.5% efficiency burning high sulfur coal)		
Conventional	8.63	8.30
With High Intensity Ionizer	3.48	2.40
Savings	5.15 (60%)	5.90 (71%)
CASE 3 - RETROFIT INSTALLATION		
(Originally, 98.5% efficiency burning low sulfur coal)		
Conventional	3.42	6.40
With High Intensity Ionizer	2.74	2.40
Savings	0.68 (20%)	4.00 (63%)
CASE 4 - RETROFIT INSTALLATION		
(Originally, 97% efficiency burning low sulfur coal)		
Conventional	5.40	8.10
With High Intensity Ionizer	2.74	3.60
Savings	2.66 (49%)	4.50 (56%)

SCA was added to the existing precipitators until, both with and without the HII, the desired efficiency would be achieved. Table 3.12 shows the amount of additional SCA which it was determined must be added in each case. In cases 2 and 3 it was determined that no additional SCA was required with the employment of the HII. A cost breakdown for the new ESP called for in case 1 is presented in Table 3.13.

3. Outline of Inherent Characteristics

The HII should serve to permit an ESP to collect more effectively with a nominal power consumption of .06 watt/acfm, an equipment cost of 60¢/acfm, and a space utilization of approximately 5' in the direction of flow. The device was tested on a 35,000 cfm scale at Arapahoe, and with some modifications performed satisfactorily. The economics of utilizing the HII hinge on the alternative costs of realizing the same enhanced collection with other devices.

Promoters of the HII claim that effective drift velocity will double for low resistivity ash. This seems like a reasonable claim at moderate efficiencies but it remains to be verified on an existing facility. The claim that the HII will double effective drift velocity on high resistivity ash seems more questionable, and a rough calculation performed in this study concludes that the effective drift velocity on high resistivity ash for moderate efficiencies can be enhanced by 25% to 33%. A strong factor in determining whether it is more economical to increase SCA or purchase the HII is the amount of retrofit space available.

E. Electrostatically Enhanced Bag Filter

1. General Description

The high efficiencies demonstrated by fabric filters have helped to

TABLE 3.12

Size data for precipitators required to meet the efficiency requirements of four case studies with and without the high intensity ionizer.

CASE	DESCRIPTION	EFFICIENCY (%)	w (cm/s)	SCA (ft^2/1000 ft^3/min)
1	New Precipitator Conventional Design.	99.5	4.0	666
	New Precipitator with High Intensity Ionizers.	99.5	8.0	336
2	Existing Precipitator was Designed for 99.5% Burning High Sulfur Coal Converted to Low Sulfur Coal.	98.2	6.2	328
	Conventional Equipment Added to A. to Retrofit to 99.5% on Low Sulfur Coal.	99.5	3.9	684
	High Intensity Ionizer Equipment Added to A. to Retrofit to 99.5% on Low Sulfur Coal.	99.5	8.2	328
3	Existing Precipitator 98.5% Low Sulfur Coal.	98.5	6.0	355
	Equipment Added to B. to retrofit to 99.5% on Low Sulfur Coal.	99.5	3.9	684
	High Intensity Ionizer Equipment Added to B. to Retrofit to 99.5% on Low Sulfur Coal.	99.5	7.6	355
4	Existing Precipitator 97% Low Sulfur Coal.	97.0	7.4	240
	Conventional Equipment Added to C. to Retrofit to 99.5% on Low Sulfur Coal.	99.5	4.1	653
	High Intensity Ionizer Equipment.	99.5	8.2	326

Table 3.13

DETAIL COST FOR LARGE NEW PRECIPITATOR - CASE 1

% COSTS OBTAINED FROM AVERAGE OF 10 LARGE MODERN PRECIPITATORS			
ITEM	COST ($)	PERCENT FOR FLANGE-TO-FLANGE, INCLUDING PLENUMS	% FOR TOTAL
High-Voltage Power	$ 732,750	9.77	8.26
Control Panels	610,500	8.14	6.88
Ext. High-Voltage System	180,000	2.40	2.03
Electrical Devices	2,250	.03	.03
	$1,525,500	20.34	17.20
Casing	1,404,750	18.73	15.83
Hoppers	906,000	12.08	10.20
Collecting System	1,226,250	16.35	13.80
High-Voltage System	514,500	6.86	5.78
	$4,051,500	54.02	45.61
Rapper System	752,250	10.03	8.47
Inlet Plenum	247,500	3.30	2.79
Outlet Plenum	232,500	3.10	2.61
Internal Access	48,750	.65	.55
External Access	106,500	1.42	1.20
Superstructure	311,250	4.15	3.51
Ventilation Equipment Support	20,250	.27	.23
Operating Floor Insulation	66,750	.89	.75
Hopper Dust Control	66,000	.88	.74
Safety Interlocks	71,250	.95	.80
SUBTOTAL	$7,500,000	100.00	84.46
Support Structure	942,200		10.61
Access Facilities	437,800		4.93
	$8,800,000		100.00

make them popular devices for industrial dust control. Several factors have delayed the use of baghouses on utility boilers to the last several years. Utility stack temperatures, generally between 200°F and 300°F can rise to 550°F if a malfunction occurs in the airheater. Only fiberglass bags can withstand these elevated temperatures, and fiberglass displays poor resistance to abrasion and therefore a short life. Teflon was introduced to the bag filter market in 1964 and features excellent abrasion resistance and temperature resistance to 450°F. Unfortunately, teflon fabric is expensive. In addition, fabric filters are large, require a significant amount of space, and consequently are expensive. The economics of fabric filters have only recently become attractive with the enactment of tighter particulate standards. EPA emission tests on two baghouse equipped coal fired utility boilers have shown the controlled emission level to be less than .018 lb/MMBtu, easily achieving the .03 lb/MMBtu new source performance standard [54]. Although the EPA document "Background Information for Proposed Particulate Matter Emission Standards" suggests that both bag filters and appropriately sized ESPs can be used to achieve the new source performance standard of .03 lb/MMBtu [55], DOE officials claim that the severity of the standard effectively precludes the use of an ESP for emissions emanating from the combustion of low sulfur coal [56]. The EPA document cited states:

> For the types of control systems studied and the parameters chosen it would appear that fabric filters are the more economical choice for low sulfur coals and electrostatic precipitators for high sulfur coals. [57]

While the collection efficiency of the standard fabric filter is adequate to achieve even the projected NSPS standard, improvements in land utilization and economics could result from an increase in operating air to cloth ratio. American Precision Industries claims that their electrostatically enhanced fabric filter, called the Apitron, can operate on a pulverized coal boiler with an air to cloth ratio of 10 cfm/ft^2 (0.5 m/sec), a level five times higher than the level recommended by the EPA for a standard fabric filter and four times higher than the rate recommend by ICA, a large utility baghouse manufacturer [58,59]. The Apitron reportedly achieved this performance improvement by charging the particulate below the bag. Although a field is not applied across the bag filter, tests have shown that a porous bag cake forms which yields a reduced system pressure drop. In addition, the Apitron reportedly yields an enhanced collection efficiency due to the electrostatic charging.

The important question for evaluation is whether the electrostatic enhancement provides benefits justifying the added expense. The Apitron filter is designed with a wire and cylinder charger beneath each "inside-out" bag. The cylinder of the charger is water cooled to help reduce ash resistivity. Figure 3.21 shows a cutaway view of a pilot Apitron unit utilized for EPA testing [60]. Note that the charging section adds a considerable amount of equipment and complexity to the standard bag filter. In addition, pulse jet cleaning is utilized to simultaneously clean the bag, charger, and upper high voltage insulator. During the cleaning cycle a pulse of compressed air is directed downward through the charging cylinder. The air entrained in this pulse collapses the bags above providing the necessary cleaning action. This cleaning technique rules out the use of fiberglass bags, necessitating the use of felted teflon. An analysis supplied by Apitron explains that although fiberglass fabric sells for $4/sq. yd., woven teflon sells

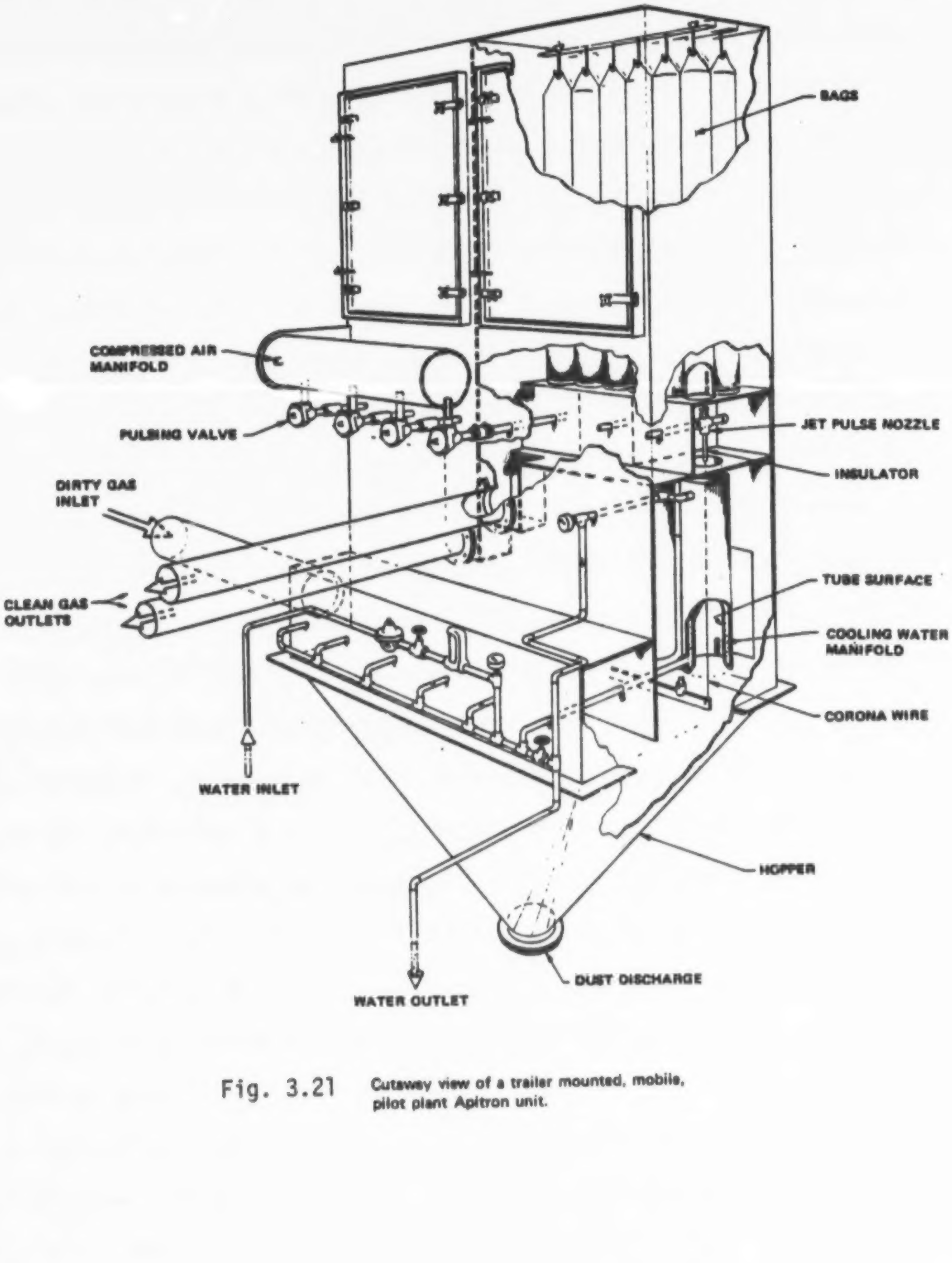

BAGS
COMPRESSED AIR MANIFOLD
PULSING VALVE
JET PULSE NOZZLE
INSULATOR
DIRTY GAS INLET
CLEAN GAS OUTLETS
TUBE SURFACE
COOLING WATER MANIFOLD
CORONA WIRE
WATER INLET
HOPPER
DUST DISCHARGE
WATER OUTLET

Fig. 3.21 Cutaway view of a trailer mounted, mobile, pilot plant Apitron unit.

for $56/sq. yd., an economic benefit can be realized through the use of the most expensive felted teflon bags [61]. This tradeoff is justified on the basis of the longer life and higher facial velocities permitted in an Apitron system. The use of felted material is required on pulse jet baghouses in order to prevent a puff from occurring after a cleaning pulse.

Although to make a direct comparison between the Apitron filter and the usual reverse-air fiberglass filter baghouse is difficult because of the enormous differences between these two approaches to fabric filtration, a comparison using a conventional pulse-jet baghouse as an intermediary is more practical. The conventional pulse-jet baghouse is generally not employed by the utility industry. A survey of particulate collection devices performed by Bechtel states, "Fly ash applications with their potential for temperature excursions to 550°F, are usually specified to have fiberglass coated bags coated with teflon or similar lubricating finish." [62] Pulse jet cleaning on fiberglass is impossible because of the poor bag life which would result. In a paper by Apitron the lifetime of teflon bags utilizing pulse jet cleaning is not directly addressed. The paper states, "Absolute values for the lifetimes that can be expected for Teflon or glass bags are impossible to determine. There are relatively few operating baghouses on boilers at this time, and even identical bags can exhibit widely differing lifetimes on different boilers or in different baghouses. However, in reviewing available data, it can be assumed that Teflon will have a lifetime approximately twice that of fiberglass on any given application." [61] Assuming that the 450°F temperature limitation of teflon is acceptable to a particular utility, the extra cost and reduced lifetime from pulse-jet cleaning cannot be justified. Pulse-jet cleaning has the additional energy requirement of generating

Figure 3.22 FLUE GAS FILTRATION PERFORMANCE

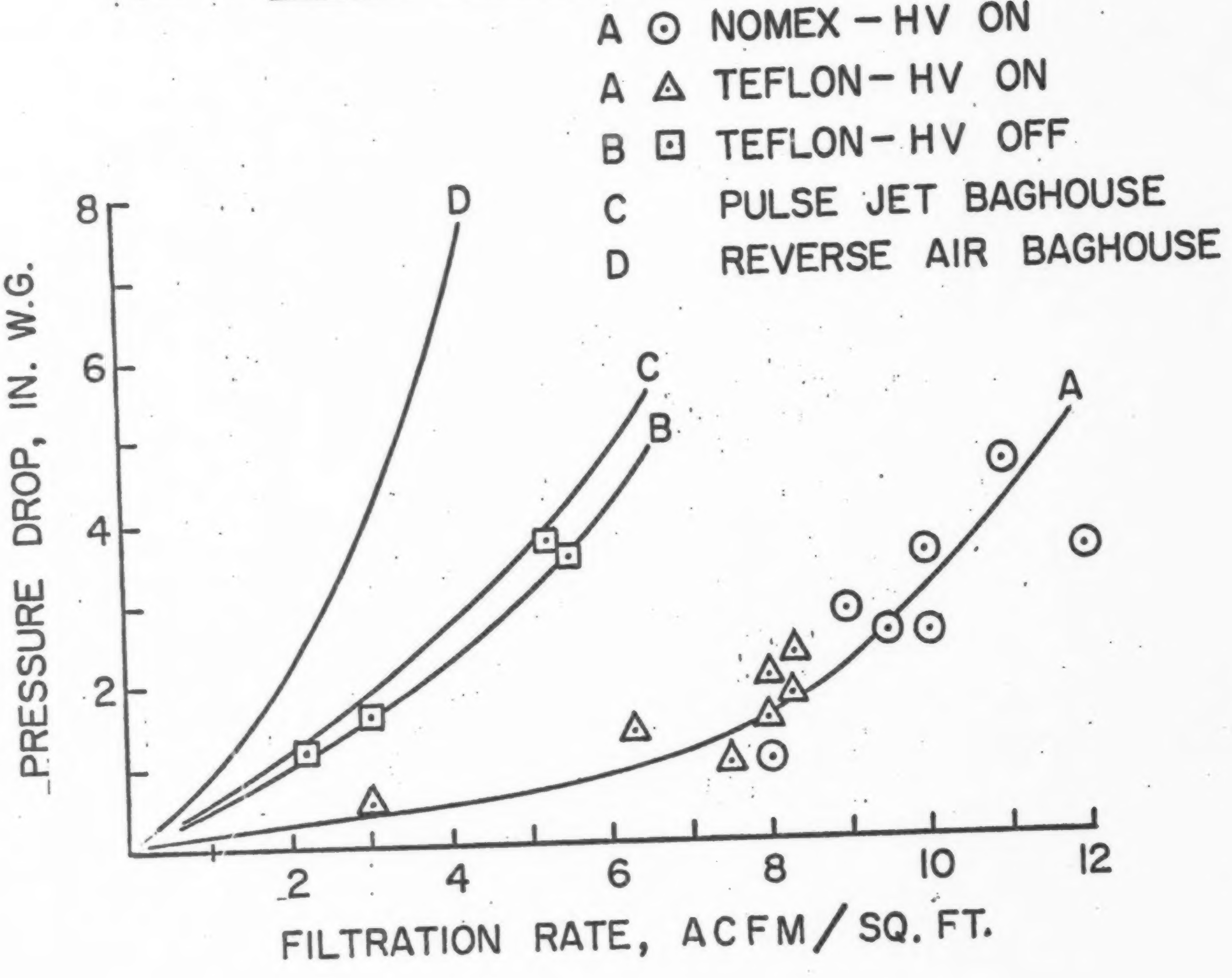


TABLE 3.14 APITRON MOBILE UNIT TEST CONDITIONS

		Outlet gas flow					ESP conditions								
				Outlet temp.	Bag Face	Velocity	Voltage	Current	Specific collecting area		Current density	Energy usage	Apitron pressure drop	Energy usage, air moving
Date	Bag Material	am^3/min	acfm	°C	mm/sec	fpm	kv	mA	m^2/am^3/s	ft^2/1000 acfm	nA/cm^2	joules/m^3	cm w.c.	joules/m^3
11/30/77	Nomex	7.31	258	74	34.7	6.83	31	7.5	8.25	41.9	750	1910	5.3	530
12/1/77	Nomex	7.00	247	77	33.2	6.53	31	7.5	8.60	43.7	750	2000	5.3	520
12/2/77	Teflon[a]	8.47	299	71	40.2	7.91	30.5	7.5	7.11	36.1	750	1620	0.5	50
12/5/77	Teflon	7.42	262	74	35.2	6.93	30	8.0	8.11	41.2	800	1940	3.0	300
12/6/77	Teflon	7.00	247	74	33.2	6.53	29	8.5	8.60	43.7	850	2120	3.8	380
12/7/77	Teflon	6.91	244	74	32.8	6.46	0	0	0	0	0	0	8.9	868
12/8/77	Teflon	2.92	103	54	13.8	2.72	0	0	0	0	0	0	3.3	323

TABLE 3.15 APITRON FULL SCALE PILOT PLANT TEST CONDITIONS

		Outlet gas flow					ESP conditions							
				Outlet temp.	Bag Face	Velocity	Voltage	Current	Specific collecting area		Current density	Energy usage	Apitron pressure drop	Energy usage, air moving
Date	Bag Material	am^3/min	acfm	°C	mm/sec	fpm	kv	mA	m^2/am^3/s	ft^2/1000 acfm	nA/cm^2	joules/m^3	cm w.c.	joules/m^3
6/12-6/14	Dacron	283	10,000	20	29.4	5.79	27	118	8.91	45.2	281	675	7.1	720
6/14-6/15	Dacron	243	8,600	24	25.3	4.98	0	0	0	0	0	0	21.6	2200
6/15-6/16	Dacron	261	9,200	22	27.0	5.32	0	0	0	0	0	0	22.9	2330
6/16-6/17	Dacron	232	8,200	24	24.1	4.75	0	0	0	0	0	0	14.6	1490
6/17-6/18	Dacron	283	10,000	24	29.4	5.79	27-33	118-190	8.91	45.2	281-432	675-1330	7.1	720
6/18-6/19	Dacron	283	10,000	24	29.4	5.79	39	325	8.91	45.2	773	2690	7.1	720

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[a] New, clean Teflon bags installed overnight of 12/1 - 12/2

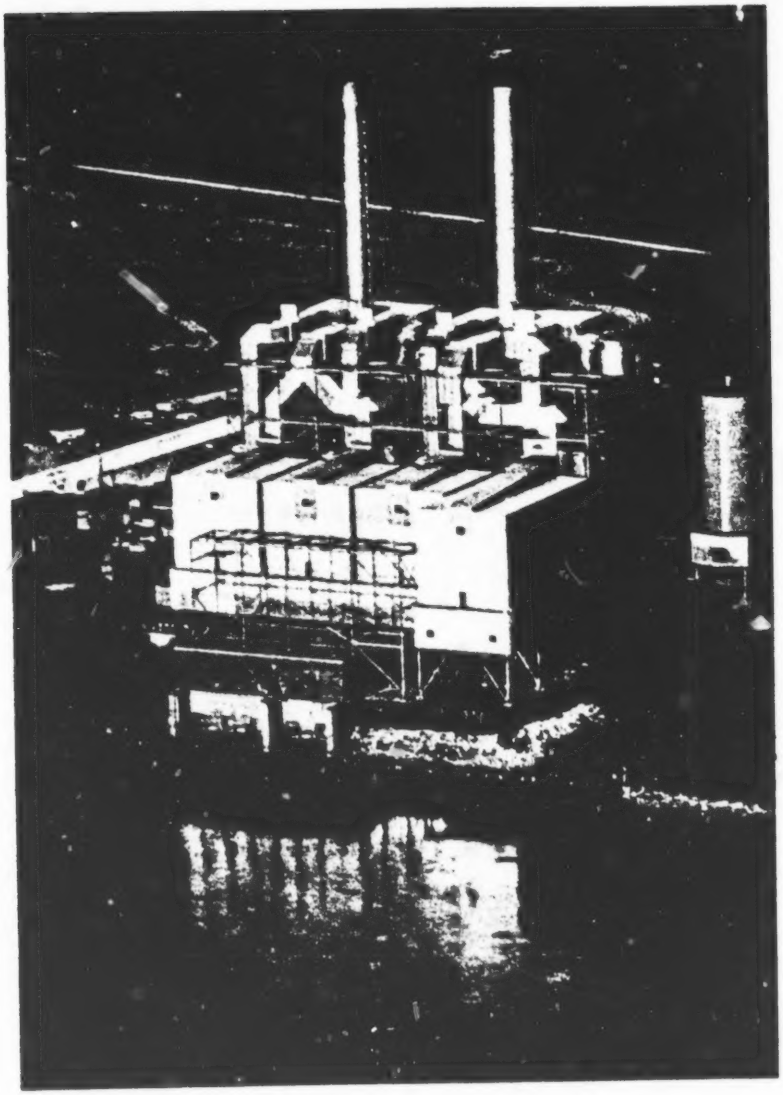


Figure 3.23 Picture of baghouse on coal fired Kramer station.

tion of Nebraska Public Power [64]. Note the enormous size of the baghouse. A direct comparison can be made between the space required by ICA for a utility baghouse and the space utilization claimed by Apitron. The Apitron model 72-8/12-8 baghouse has a flow capacity of 115,200 cfm at an A/C ratio of 8 fpm, and requires 720 ft^2 of ground area [65]. A drawing of a full-scale Apitron module is provided in Fig. 3.24. These numbers lead to a ratio of flow capacity to ground area of 160. The ICA #7-3200ANS boiler baghouse features a flow capacity of 112,000 cfm, and requires 1534 ft^2 of ground area [59]. The ratio of flow capacity to ground area for this filter is 73. Both filters require approximately 30' of head room. The ratio of these two values reveals that the Apitron system with Teflon bags and pulse-jet cleaning requires a factor of 2.2 less ground area than the standard ICA filter with glass bags. For a standard pulse-jet baghouse this ratio should be reduced to approximately 1.6.

2. State-of-the-art, Development Requirements

Background information for anticipating the effects of electrostatic enhancement is provided in a two part EPA study entitled "Electrostatic Effects in Fabric Filtration." [66] Volume 1 of this study entitled "Fields, Fabrics, and Particles" was written by Professor Penney of Carnegie Mellon. Penney conducted a number of experiments to gain insight into the effects of particle charging and applications of fields on fabric filters. He stated:

> These tests indicate that, under the proper conditions, a significant reduction in pressure drop can be obtained, if the particles are charged, and if there is a field driving the particles toward the filter. However we do not know of any industrial situation in which the particulates have the necessary charge as the dust ori-

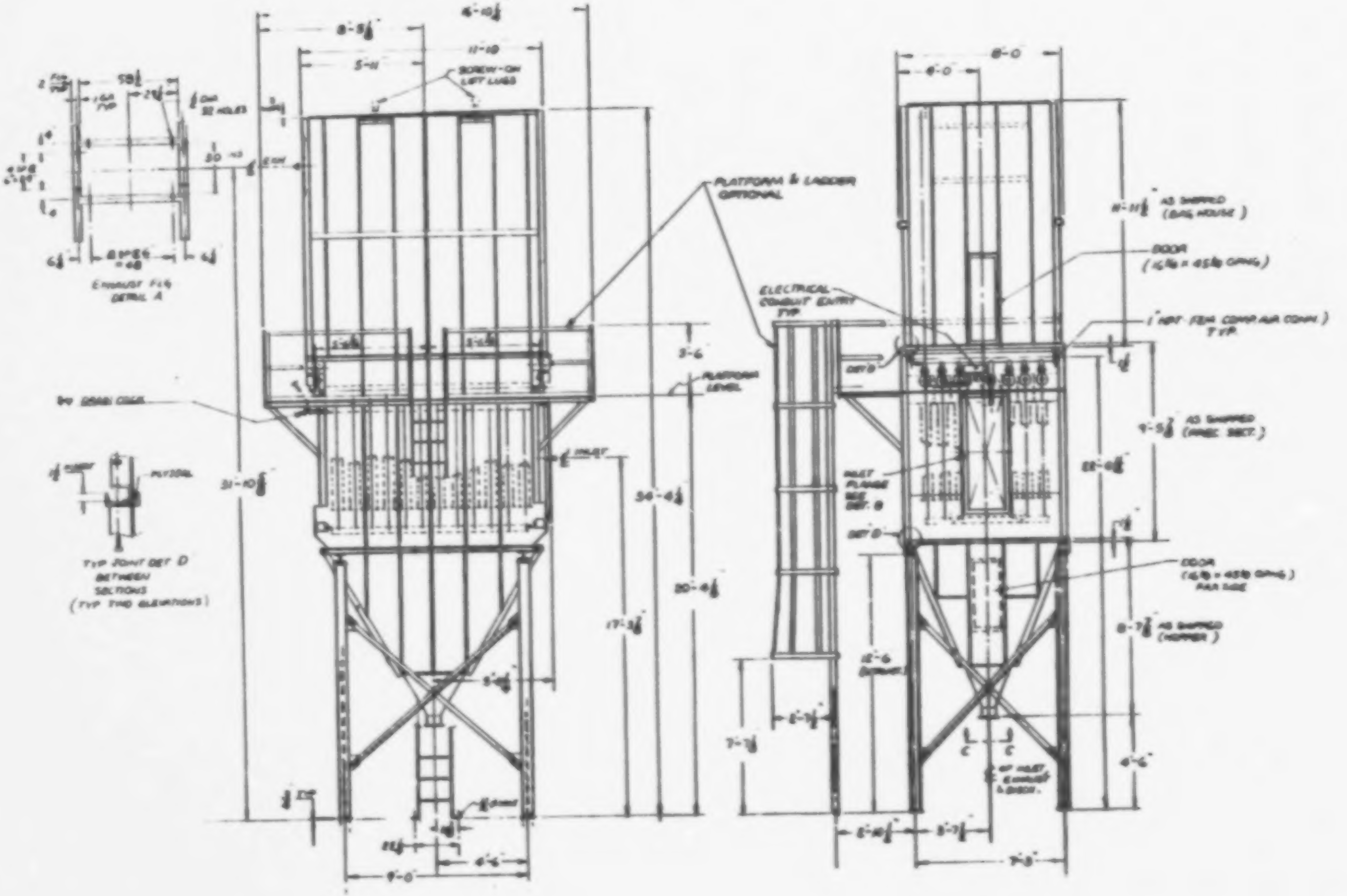

8'-0
6'-0
11'-11⅛" AS SHIPPED (BAG HOUSE)
DOOR (16⅞ × 45⅞ OPNG)
1" NPT FEM COMP AIR CONN TYP.
9'-5⅞" AS SHIPPED (PREC SECT.)
22'-6⅝"
DOOR (16⅞ × 45⅞ OPNG) PAR SIDE
8'-7⅞" AS SHIPPED (HOPPER)
4'-6"
7'-3"
ELECTRICAL CONDUIT ENTRY TYP
INLET FLANGE SEE DET. B
DET D
PLATFORM & LADDER OPTIONAL
PLATFORM LEVEL
3'-6
30'-4⅛
34'-4⅛
17'-3⅞"
12'-6
7'-7⅛
SCREW-ON LIFT LUGS
8'-5⅛"
5'-11
11'-10
16'-10⅛"
31'-10⅛"
9'-0"
4'-6"
EXHAUST FLG DETAIL A
TYP JOINT DET D BETWEEN SECTIONS (TYP TWO ELEVATIONS)

Fig. 3.24 Assembly drawing of 72 bag Apitron module.

> ginates. Also most dusts have too high resistivity for satisfactory charging by corona. So there is no obvious application in industry. If work on precipitation should develop a means for charging high resistivity dust that would open up new possibilties both in precipitation and filtration. [67]

Penney provides Figure 3.25 which shows the buildup of pressure drop over time for a filter across which 3.4 kV/cm has been applied, and an identical filter without an applied field [68]. The aerosol for both tests is charged in corona. Penney does not conduct a test which shows a direct comparison between charged and uncharged aerosol, both being collected on a fabric filter without an applied field. This comparison at first glance would seem critical for judging the effectiveness of the Apitron concept where no field is imposed across the filter.

In fact, Penney points out that the effect of applying an electric fields on his 1 ft^2 outside to in test filter can be simulated through space charge with an inside to out filter, such as the Apitron. Penney states, "If then this charged aerosol is blown inside of a filter bag, the space charge due to the charge on particles gives an electric field driving particles towards the bag," Penney also states, "If then an electric field is provided to drive particles toward the fabric, the particles are deposited primarily on the fabric rather than in the fabric. Furthermore, the dust deposit for filter cake tends to be of a porous nature, giving a low pressure drop." [69] Consequently the data in Fig. 3.25 is a partial simulation of the effects of charging in the Apitron filter, except Penney applies an electric field in his test through a pair of electrodes. Penney points out that for his test with no electric field applied migration velocities

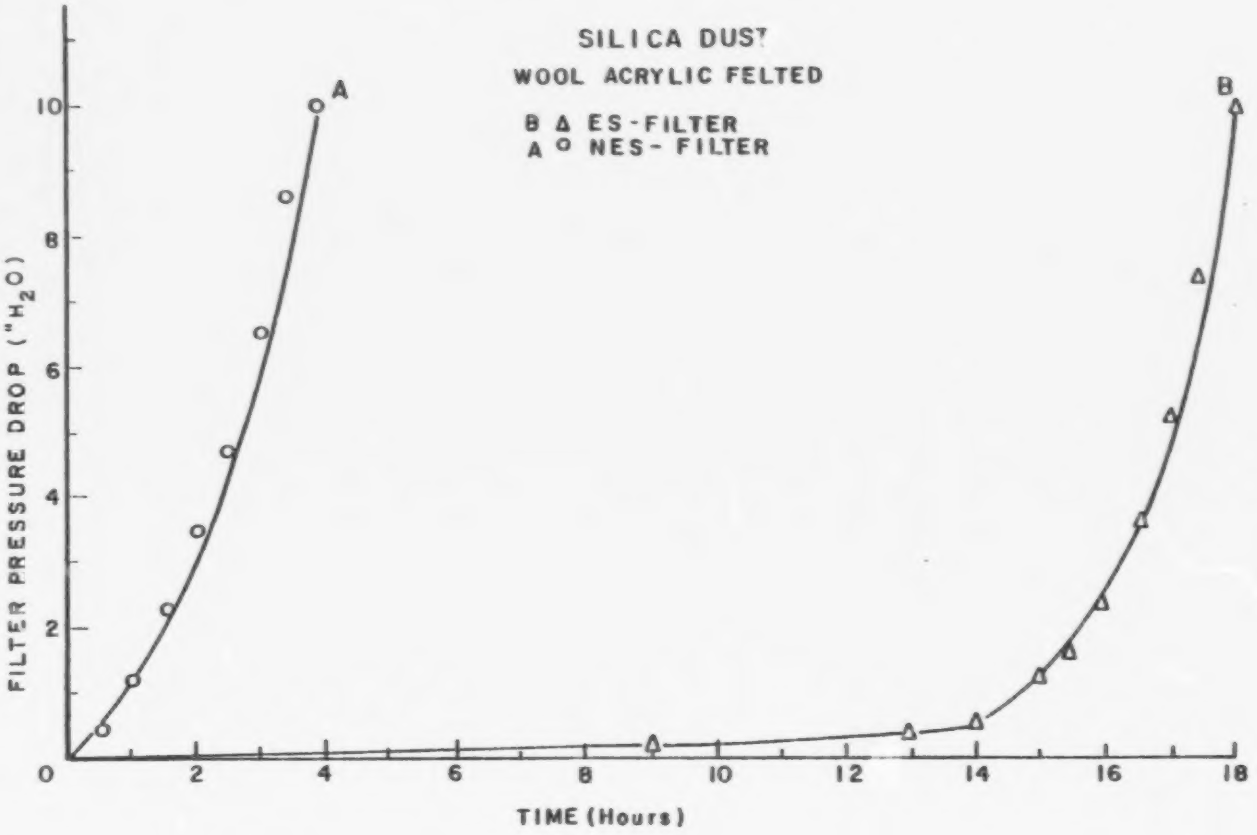


Fig. 3.25 Pressure drop versus time for fabric filter with and without applied electric field.

should be lower than air flowrates in the vicinity of the bag.

Penney's primary reservation with the use of electrostatic forces in bag filters centers around the problems of charging and carrying away the charge from highly resistive dust. Penney states that problems with corona charging begin with dusts of higher resistivity than 2 x 10^{10} ohm-cm, and that most industrial dusts have a resistivity of 10^{11} ohm-cm or more. "Furthermore, even if the dust can be charged, there is another limit on the order of 10^{14} ohm-cm above which conductivity of the collected dust cannot carry away the charge on the arriving dust." [69] The Apitron system deals with the problem of ash resistivity by cooling the grounded cylinder of their corona charger with a jacket of water (see Fig. 3.21). Apitron has made no statement concerning the effectiveness of this system, although in principal bringing collected ash below the gas dewpoint should have a significant increasing effect on conductivity. This system should have an additional negative effect of increasing system corrosion due to acid. The parameters of the Apitron pilot test program on pulverised coal emissions are reported in Table 3.14. The results of this program are reported in Table 3.16 [70]. Note that this test program did not provide a meaningful trial of the resistivity problem because of the high effective dilution in the ductwork and the gas temperatures below 80°C. Due to problems with the use of unseasoned bags during the first series of tests the EPA sponsored a second series of tests on an Apitron filter collecting redispersed silica dust. The parameters of those tests on a full-scale system are reported in Table 3.15, and the results of those tests are reported in Table 3.17 [70]. Although impressive efficiency results are reported for the tests in Table 3.17, these results are well beyond the requirements of the utility industry, and the incremental

TABLE 3.16 PERFORMANCE TESTS RESULTS FOR THE MOBILE APITRON PILOT PLANT

Date	Inlet loading, mg/DNm^3	Outlet loading, mg/DNm^3	Dilution correction factor	Collection efficiency, %	Total energy usage	
					joules/am^3	hp/1000 acfm
12/1/77	4600	10.6	1.79	99.59	2520	1.60
12/2/77	3940	4.26	1.46	99.84	1670	1.06
	4580	5.54				
12/5/77	5580	3.43	1.60	99.902	2240	1.42
12/6/77	4960	2.09	1.50	99.940	2500	1.58
	6150	2.33				
12/7/77	2170	0.99	1.63	99.905	868	0.55
	2060	1.50				
	2150					
12/8/77	3230	1.20	1.89	99.928	323	0.20
	2950	1.14				

TABLE 3.17 PERFORMANCE TEST RESULTS FOR THE FULL SCALE APITRON UNIT

Date	Inlet loading, mg/DNm^3	Outlet loading, mg/DNm^3	Collection efficiency, %	Total energy usage	
				joules/am^3	hp/1000 acfm
6/12 - 6/14	12800	0.172	99.9987	1370	0.87
6/14 - 6/15	12600	0.480	99.9962	2120	1.35
6/15 - 6/16	12800	0.366	99.9971	2250	1.43
6/16 - 6/17	12400	0.126	99.9990	1440	0.91
6/17 - 6/18	12800	0.119	99.99907	1750-2400	1.11-1.52
6/18 - 6/19	12800	0.094	99.99927	3580	2.27

efficiency is of questionable value. In order to gather a measurable sample for the tests reported in Table 3.17 outlet samples had to be gathered for a one to two day period. An efficiency as a function of particle size for the test run 6/18-19 is presented in Fig. 3.26 [71].

Additional insight into electrostatic effects in fabric filtration is provided by the companion study to Penney's on triboelectric effects [72]. The author of the study states in the preface, "Accordingly, in this report, the importance of, in fact, the critical need for, suitable electrostatic charge balancing (between medium and particulate) and obtainable naturally without augmentation, is stressed as the mechanism by which optimal filtration performance may be achieved." The study advocates that a matching be made between the electrical properties of particulate and the triboelectric properties of the filter medium. In the abstract the report states with respect to flyash, "The collection of a flyash, for example, was favored by the use of midtriboelectric position media and not by the highly electropositive or electronegative fabrics that are employed for their high temperature properties." Both fiberglass and dacron are in the mid-triboelectric position favored in this study for flyash collection. The full-scale Apitron tests reported were conducted with dacron bags. Teflon, the fabric of choice by Apitron for flyash collection, is extremely electronegative and highly resistive. The high resistivity in this fabric could cause high electric fields between the collected ash layer and the bag support cage [73].

Many questions and unknowns about the Apitron system will be addressed by the upcoming test of a full-scale unit at the EPRI test facility in Arapahoe. As of the time of writing this unit has not yet begun operation, but reportedly test results should become available sometime

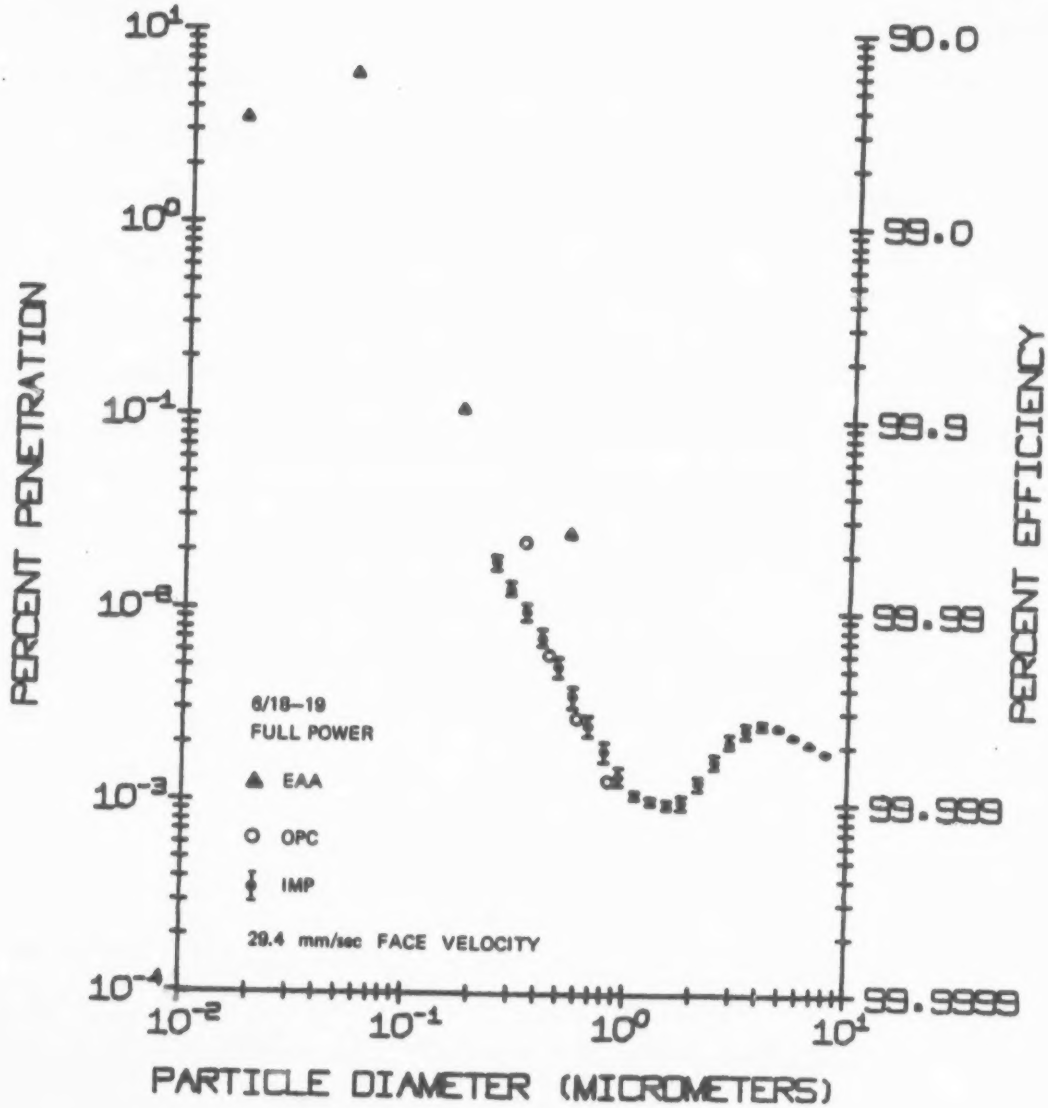


Figure 3.26 Fractional efficiency of the full scale Apitron unit at full electrical energization vs. Stokes particle diameter in micrometers.

during 1979.

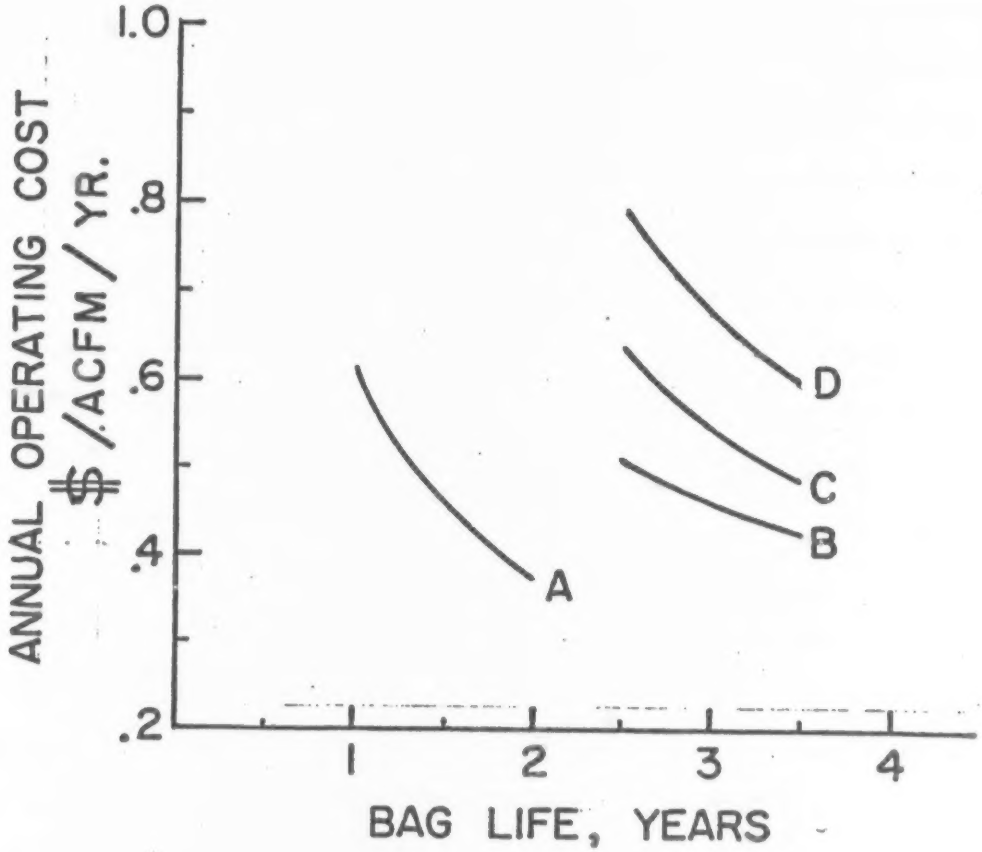
An exact cost for an Apitron filter has not yet been published, but promoters of the device claim that the capital expense will be similar to a reverse-air and pulse-jet system. Apparently the added cost of the electricals is compensated for by the reduced system size. Apitron supplies Fig. 3.27 to compare the operating costs of various types of baghouses [61]. This calculation accounts for bag replacement and pressure drop cost, but apparently does not account for compressed air for bag cleaning in the Apitron and pulse-jet systems. The Apitron filter requires 30 scfm of compressed air at 80 psig for a 25,000 acfm unit [74]. Considering typical compressor characteristics, this is equivalent to 676 J/m^3 of electrical input [75]. From a study by Bechtel the capital cost in 1980 dollars for a reverse air baghouse for installation on a 677 MW plant is $4.76/acfm, exclusive of erection costs [76].

3. Outline of Inherent Characteristics

The Apitron system offers the high collection efficiencies typical of bag filters with a promise of a reduced space requirement and a lower system pressure loss. Some questions remain as to whether the system's corona ionizer will be able to operate effectively on pulverised coal emissions. These questions should be answered by tests to be conducted at the EPRI test facility in Arapahoe. With or without electrical enhancement the system does not appear to offer a significant improvement in performance over the conventional pulse-jet filter with teflon bags which it closely resembles. The utility industry has repeatedly passed over the pulse-jet system with teflon in favor of the reverse air system with fiberglass bags. Therefore, at this stage of development the Apitron filter seems unlikely to make a significant impact on the utility industry.

FIGURE 3.27

OPERATING COSTS FOR FABRIC FILTERS ON COAL FIRED BOILERS



A	REVERSE AIR - FIBERGLASS
B	APITRON - TEFLON FELT
C	REVERSE AIR - WOVEN TEFLON
D	PULSE JET - TEFLON FELT

F. Wet Electrostatic Precipitator

1. General Description

A wet-wall ESP is an ESP with the collection plate covered by a thin film of water. In the case of the Fluid-Ionic system considered here collection electrodes are arranged as concentric cylinders. Water is continually pumped to the top of these cylinders and it serves not only to capture and carry away pollutant particles, but also as the device ground electrode, with the corona current passing through the water to the collector plumbing system. The use of water as an electrode allows Fluid-Ionics to build the system almost entirely of industrial FRP, (fiberglass reinforced plastic), a fiberglass known for its resistance to corrosion. The discharge electrode in the collector is composed of alloys such as hastelloy or stainless steel, making the overall system quite resistant to corrosion. Corrosion resistance is an essential feature for wet collectors because the flue gases generally contain water soluble materials which form acids.

Fluid-Ionic has been selling their Hydro-Precipitrol collector since 1974 when they received the exclusive right to manufacture and sell the collector from Seversky Electronatom Corporation, a company started by Major de Seversky. Sales to this point have been primarily in the metallurgical industries, with a total of 40 units in the field to date. A significant accomplishment for the company was the sale of 16 units to control the emissions from the Reserve Mining taconite mill in Silver Bay, Minnesota. Wet electrostatic collectors have not made an entry to the utility market at this point because of the corrosion problems and the cost of reheating the saturated plume. Plume reheat is essential after the use of a wet collector since a negatively buoyant plume could result in excessively high pollutant ground level concentrations. Although plume reheat is expensive, the incremental cost of plume reheat is zero if wet stack gas scrubbing is employed. The Hydro-Precipitrol contains a wet scrubber at the base of the collector and EPA tests have been conducted which have demonstrated the capability of the collector for combined collection. Figure 3.28 shows a cutaway view of the collector illustrating the lower cyclonic wet scrubber and the upper electrostatic collector [77]. Note that the electrostatic collector is drained separately from the scrubber through the venturi inlet vanes, and that the upper electrostatic collector serves as the scrubber mist eliminator. The SO_2 collection tests conducted utilized the double alkali process, since the collector is not equipped for dealing with large amounts of solids and potential scaling problems. Steve Jaasund of Fluid-Ionic reports that the EPA report on the SO_2 collection tests will not be available until the summer of 1979, but that collection efficiencies of 90% for SO_2 were achieved in the tests [78]. Mr. Jaasund reports that he prefers to keep suspended solids levels in the collector below the 800 ppm level.

Only one size collection module of the Hydro-Precipitrol is currently available [79]. This module contains an electrostatic collection section 10' high with 72 ft^2 of open area to accommodate gas flow. This module currently sells for $350,000 complete with the scrubber, collector, stack and power supplies. The flow capacity of a module will vary from between 30,000 and 100,000 cfm in the saturated 150°F condition. This flow is equivalent to a flow 16% larger at 250°F stack gas temperatures. Figure 3.29 shows an elevation drawing of three collectors ducted together. Not only the inlet ducting but also the stacks could be readily ducted together to serve utility requirements.

The system requires an overall pressure drop of 1" W.G. and high voltage power supplies along with the hot purge air blowers require 20 KW

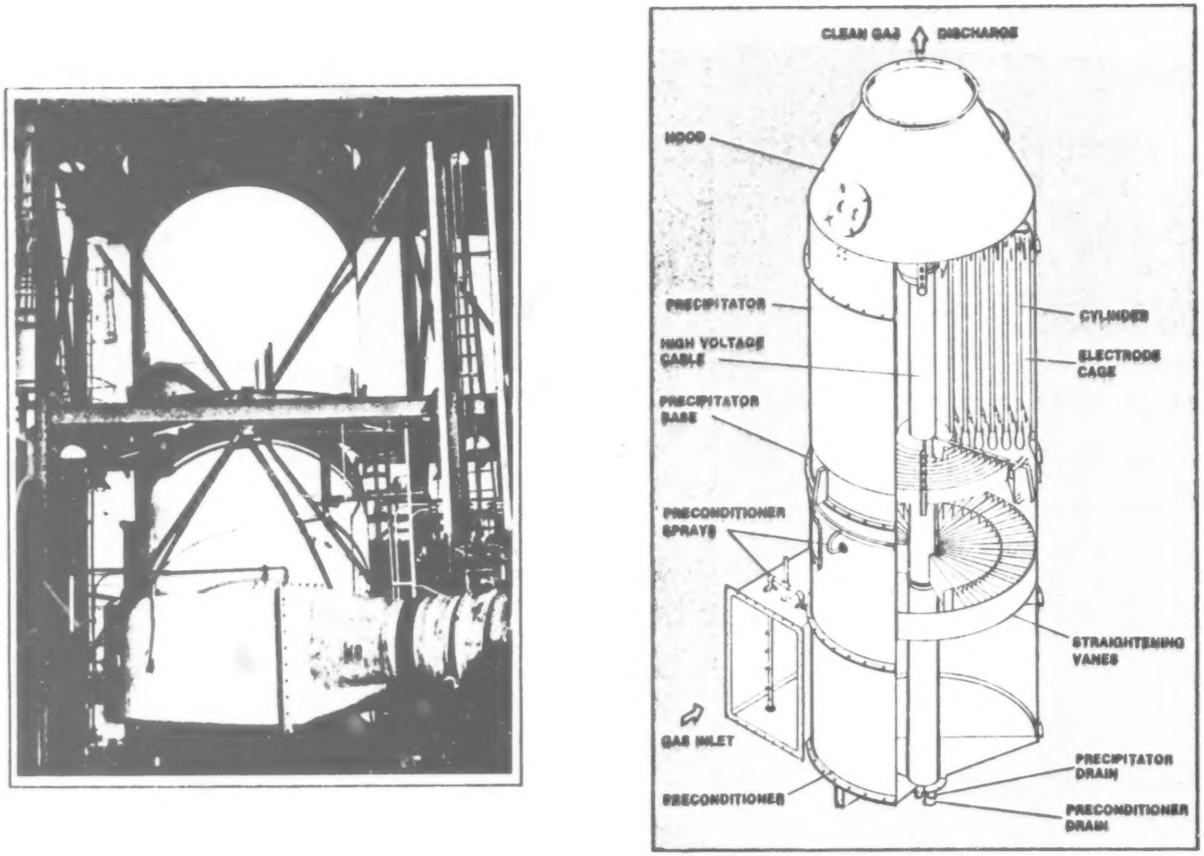

CLEAN GAS
DISCHARGE
HOOD
PRECIPITATOR
HIGH VOLTAGE CABLE
PRECIPITATOR BASE
PRECONDITIONER SPRAYS
GAS INLET
PRECONDITIONER
CYLINDER
ELECTRODE CAGE
STRAIGHTENING VANES
PRECIPITATOR DRAIN
PRECONDITIONER DRAIN

Figure 3.28 Picture and sketch of Fluid-Ionic wet electrostatic precipitator.

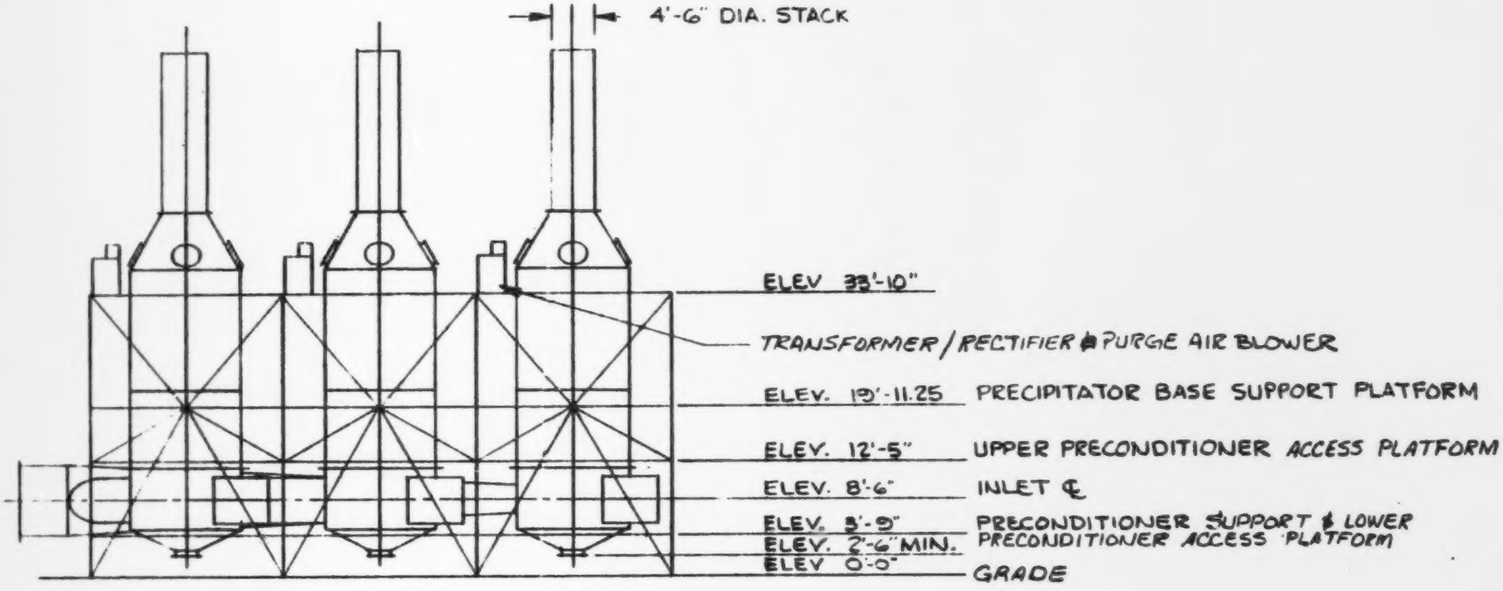

4'-6" DIA. STACK
ELEV 33'-10"
TRANSFORMER / RECTIFIER & PURGE AIR BLOWER
ELEV. 19'-11.25 PRECIPITATOR BASE SUPPORT PLATFORM
ELEV. 12'-5" UPPER PRECONDITIONER ACCESS PLATFORM
ELEV. 8'-6" INLET ℄
ELEV. 3'-9" PRECONDITIONER SUPPORT & LOWER
ELEV. 2'-6" MIN. PRECONDITIONER ACCESS PLATFORM
ELEV 0'-0" GRADE

Fig. 3.29 Elevation drawing for three Hydro-Precipitrol modules ducted to operate in parallel.

per module [79]. A significant innovation incorporated into the system is the use of one large high voltage insulator to support the entire high voltage discharge assembly. This enormous insulator can reportedly rigidly hold the entire discharge assembly between the 6" spaced ground electrodes.

2. State-of-the-art, Development Requirements

The Hydro-Precipitrol offers 72 ft^2 of facial collection area per module, and this collection area extends for 10'. A 3" spacing from discharge electrode to ground electrode is employed. The imposed electric field across this spacing ranges from 26 KV to 40 KV, with 32 KV as a nominal value. A rough calculation of system efficiency can be made using a low flow velocity of 38,000 cfm and the nominal electric field strength. At this low flowrate the system has an active residence time of 1.14 sec. Using a nominal submicron mobility of 10^{-7} $m^2/Vsec$ the characteristic collection time should be 1.81 seconds. Using the well known Deutsch equation an ESP efficiency of 47% is calculated. Overall efficiency for the unit can be considerably higher because the wet scrubber will remove larger flyash particles, and the ESP section will also be more effective on the larger particles. Despite these enhancements, it would seem unlikely that the overall system would be efficient enough to provide the 99% overall efficiencies required for coal combustion. Plants burning oil need not obtain such a high efficiency, but oil emissions are even harder to collect and there does not seem to be a strong incentive at this time for employing a wet SO_2 scrubber on oil emissions.

The low calculated efficiency of the wet collector does not correspond to the measured collection efficiencies claimed by the manufacturer. Pilot plant tests of Kraft pulp mill emissions with a facial velocity similar to our calculation showed a collection efficiency of 99% on particles with a mass median diameter of from 0.6 μm to 1.0 μm. This anomaly was not clearly explained by Mr. Jaasund [78]. Independent test results of the Hydro-Precipitrol efficiency could not be furnished by the manufacturer for this study. Other collection efficiencies reported for the metallurgical and paper industries reported similar efficiencies [80].

The cost of \$9.20/cfm for the system illustrates the significant expense associated with wet collection. The system will look more attractive as development work continues on using the volume for combined SO_2 and particulate collection, with the electrostatic collection serving a dual role as mist eliminator and fine particle collector. This advantage should be difficult to realize because of the difficulties presently encountered in conventional wet scrubbers in the areas of pumping slurries and scaling. A double alkali system can conceivably circumvent this problem, but calls for a significant amount of processing outside to the active collection volume.

3. Outline of Inherent Characteristics

The Hydro-Precipitrol offers a very attractive geometry for wet-wall ESP collection. The use of one large insulator per module reduces the difficulties of maintaining high voltage in a wet environment. The fiberglass construction of the system reduces corrosion problems to a minimum. The present module size would call for typically 40 modules for a power plant, and consequently a large space requirement. This situation could be circumvented through the fabrication of larger modules.

The Hydro-Precipitrol can be considered for applications where wet scrubbing is mandated, and recent EPA tests have demonstrated the capabilities of the device for both wet scrubbing and particulate collection. The wet electrostatic collector can perform both particulate collection and mist elimination in one step. Significant unknowns with respect to the system concern the low calculated efficiency and high $9.20/cfm sale cost. This cost is significantly higher than dry collectors which should offer higher efficiency.

G. Charged Droplet Scrubber

1. General Description

A charged droplet scrubber is a device in which water droplets are charged in order to enhance their collection performance, particularly of fine particulate. Wet scrubbers primarily collect particulate through inertial impaction, a mechanism which relies on forcing particulate to cross gas streamlines as droplets move through the gas. Since settling velocity is proportional to the particulate radius squared, extremely high velocities of droplets with respect to the gas are required to achieve collection below 5 μm. One approach to solving this problem has been to supply the energy required with a venturi scrubber. Another intrinsically more attractive approach is to charge the droplets and particulate to opposite signs, so that electrostatic attraction will force particulate to cross gas streamlines.

As was discussed in the previous section a power plant must pay a large penalty for creating a wet and negatively buoyant plume. Plume reheat must be utilized to prevent the occurrence of fumigation episodes near the plant. But there is no incremental penalty for wet collection if wet SO_2 scrubbing is utilized. In fact, the current interest with charged droplet scrubbing is focused on the combined capabilities of these devices. The EPA support document forthe currently proposed New Source Performance Standard suggests that wet scrubbers are not capable of achieving the mandated emission standard of .03 lb/MMBtu [81]. Since a 90% reduction in potential SO_2 emissions is also mandated in this standard the use of separate pollution control devices is apparently required. Dry scrubbing, discussed with respect to the Electrified Bed could circumvent this problem. Electrostatic enhancement of a wet scrubber for particulate control could also circumvent the two collector problem.

The University of Washington charged droplet scrubber was tested on a slipstream from the Centralia power plant, a unit burning 0.5% - 0.75% S coal with a heat value of 8100 Btu/lb [82]. This 1500 cfm charged droplet scrubber (CDS) is contained in a trailer which can easily be moved from one testing site to another. The device is designed, operated and tested by a group from the University of Washington led by Professor M.J. Pilat. In the recommendations section of the report sponsored by the EPA Pilat states, "We also recommend that the pilot plant be used to demonstrate its effectiveness for simultaneous control of particulate and SO_2 emissions from coal fired boilers. Although the charging of water droplets has been well demonstrated, the charging of droplets containing high levels of suspended solids has not. Although a double alkali approach circumvents the problem of injecting high levels of solids into the active volume, this approach is intrinsically more complex. The combination of these two technologies should not be considered straightforward and will require additional development.

The University of Washington charged droplet scrubber (CDS) contains three passes. Figure 3.30 shows the two ionizer and spray tower sections in series, followed by an electrostatically enhanced mist eliminator [82]. Pollutant is negatively charged by corona in the two ionizer sections, and positively charged water droplets are injected in the two spray tower sections. Figure 3.31 illustrates the ionizer section and Fig. 3.32 illustrates the spray towers [82]. The EPA report mentions that droplets are charged by

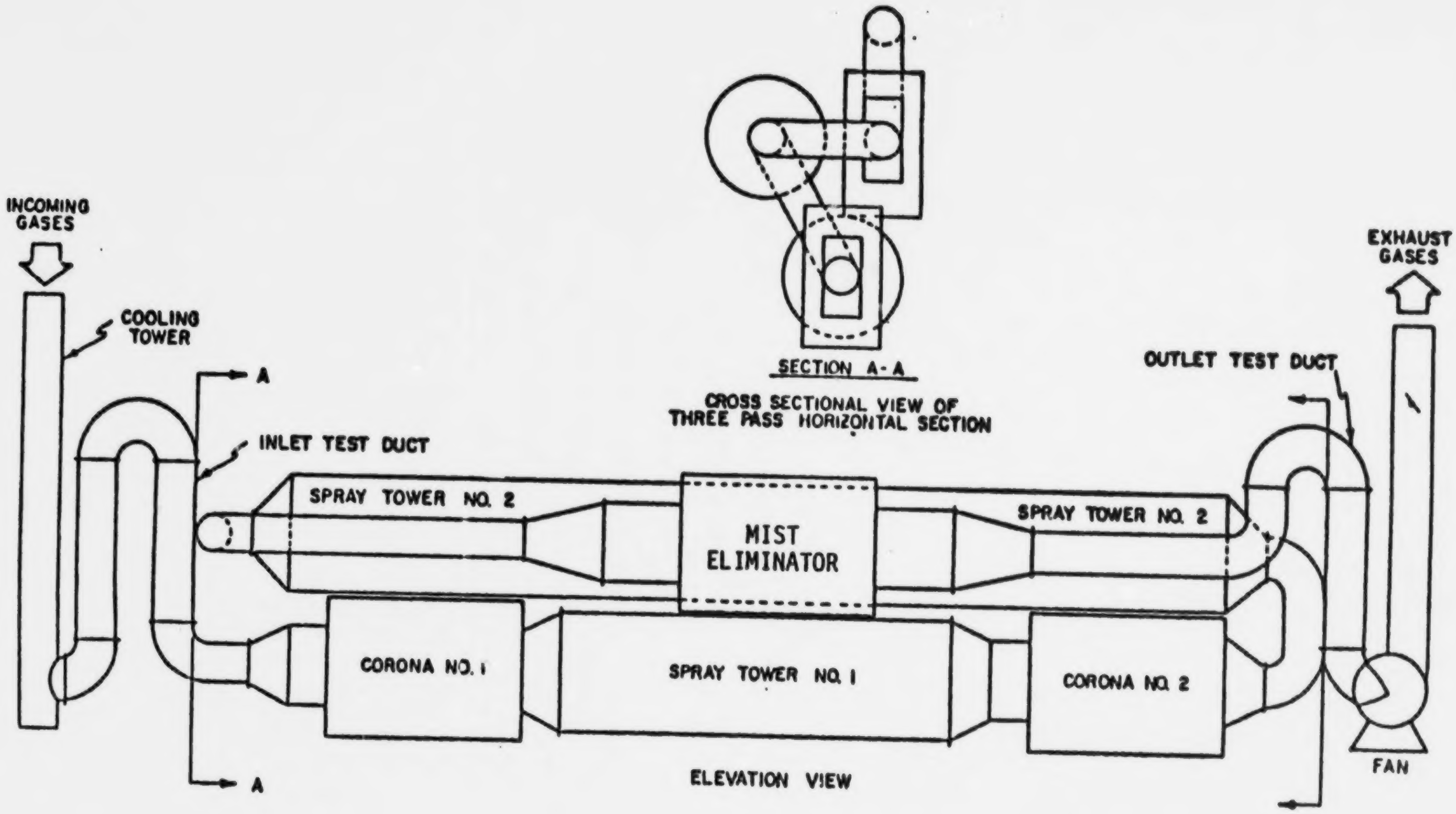

INCOMING GASES
COOLING TOWER
A
INLET TEST DUCT
A
SECTION A-A
CROSS SECTIONAL VIEW OF THREE PASS HORIZONTAL SECTION
EXHAUST GASES
OUTLET TEST DUCT
SPRAY TOWER NO. 2
MIST ELIMINATOR
SPRAY TOWER NO. 2
CORONA NO. 1
SPRAY TOWER NO. 1
CORONA NO. 2
FAN
ELEVATION VIEW

Fig. 3.30 General Layout of Electrostatic Scrubber Pilot Plant

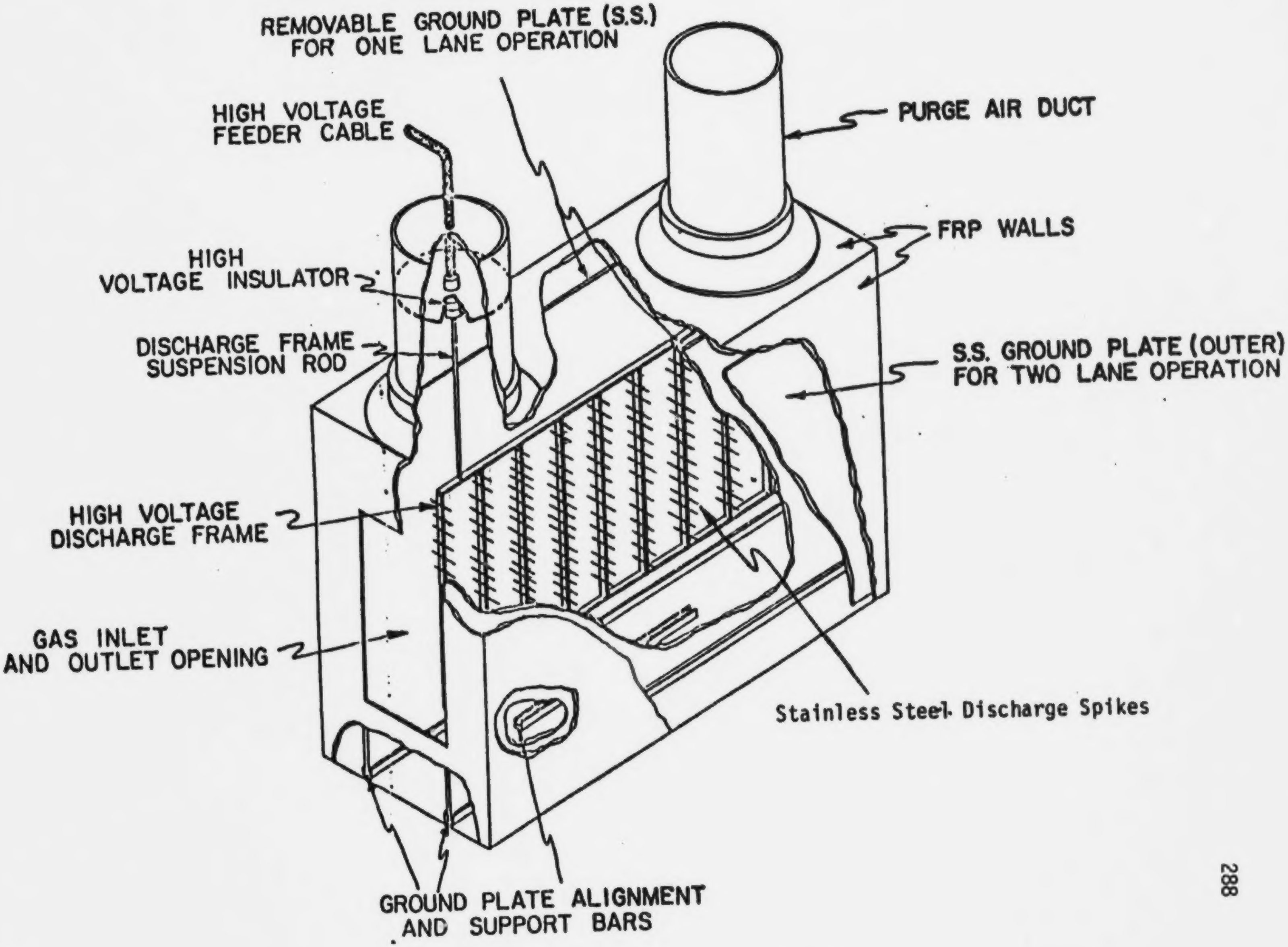

REMOVABLE GROUND PLATE (S.S.)
FOR ONE LANE OPERATION
HIGH VOLTAGE
FEEDER CABLE
PURGE AIR DUCT
FRP WALLS
HIGH
VOLTAGE INSULATOR
DISCHARGE FRAME
SUSPENSION ROD
S.S. GROUND PLATE (OUTER)
FOR TWO LANE OPERATION
HIGH VOLTAGE
DISCHARGE FRAME
GAS INLET
AND OUTLET OPENING
Stainless Steel Discharge Spikes
GROUND PLATE ALIGNMENT
AND SUPPORT BARS

Fig. 3.31 Particle Charging Corona Section

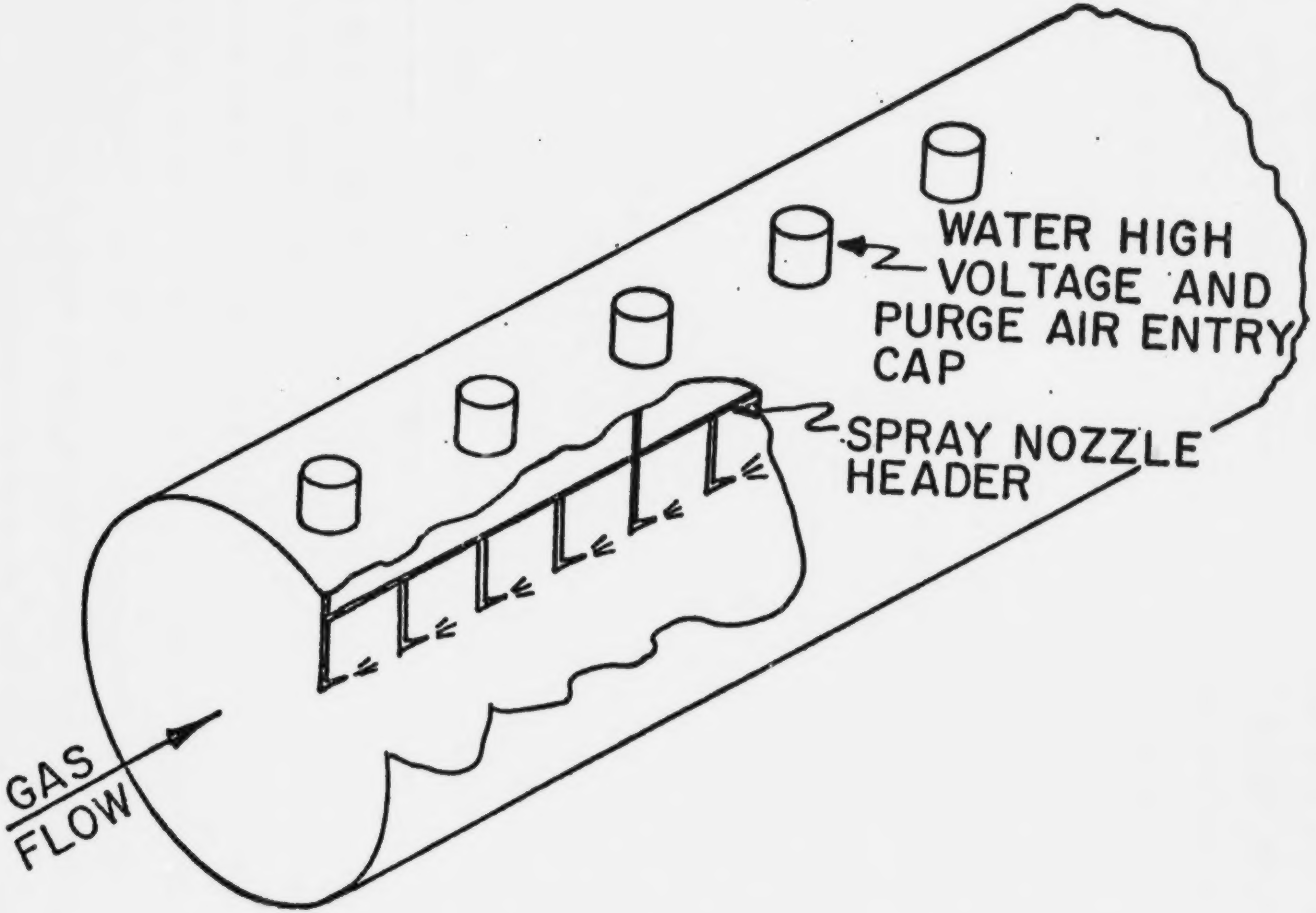

WATER HIGH
VOLTAGE AND
PURGE AIR ENTRY
CAP
SPRAY NOZZLE
HEADER
GAS
FLOW

Fig. 3.32 Spray Header and Nozzle Arrangement Typical to Spray Towers #1 and #2.

holding the spray nozzles at high voltage. This is intrinsically an attractive method compared to either induction charging or corona charging. A disadvantage of this concept is that charging current can run down the water into the plumbing system. In some applications this problem is solved by running long lengths of water tubings to build up resistance to current flow. In the University of Washington system this problem is solved by holding the pump and water system at high voltage [83].

Significant amounts of purge air are required to maintain high voltage insulation capabilities in a wet environment. For the 1500cfm test this purge air is supplied at a rate of up to 500 acfm at 150°F. Presumedly a much smaller purge air to primary flow ratio would be required on a full-scale system, but for this test the ratio is as high as 1/3. The primary gas flow is cooled by water spray to 250°F in a pretreatment cooling tower to protect the structural integrity of the FRP collection section. The use of FRP is required in applications where wet flue gases can cause acid corrosion.

Two other approaches to electrostatic wet scrubbing were taken by TRW [84] and RP Industries [85]. TRW employed direct charging of water droplets with a long length of plumbing to reduce the leakage of current back through the plumbing system. In the TRW system pollutant particles were collected mechanically through the rapid motion of charged droplets being precipitated to the walls, and pollutant was charged to the same sign as the droplets through corona emanating from the spray nozzles and even the droplets themselves. Although the TRW system found some commercial success in Japan it has since been adandoned as a commercial venture by TRW. Another approach to electrostatic enhancement of wet scrubbing was adopted by RP Industries with their Electro-Dynactor. In this device pollutant particles are charged by corona and water droplets are injected uncharged. This device works primarily through self precipitation of pollutant to the walls and droplets, mechanical collection by the droplets, and an enhancement of mechanical collection caused by the image force attraction of the charged particulate. Although image forces are not significant at average spacings calculated by droplet and particulate loadings, they can assist when droplets and particulate are brought close together through their relative motions. RP Industries has recently been put out of business and the Electro-Dynactor is no longer commercially available.

2. State-of-the-art, Development Requirements

A framework for understanding the mechanisms of electrostatically enhanced wet scrubbers is provided in the work performed by MIT for the EPA entitled, "Charged Droplet Scrubbing of Submicron Particulate" [86]. In this research the concept of using time constants to evaluate the relative value of air pollution control devices is developed. The characteristic collection time of a device illustrates the amount of active collection volume required to achieve a set amount of collection. Since the flue gas volume of an emission source is set by the production process, the volume of a pollution control device dictates the average time period in which gas is treated. Table 3.18 shows the results of two-stage tests conducted during the Centralia program. Excellent collection efficiencies were observed during these tests, but consideration must be given to the large treatment times employed. The last three columns of Table 3.18 show the gas residence time, which for two-stage operation is typically 15 sec. This residence time is equivalent to the largest ESPs used for the collection of emissions from low sulfur coal. Figure 3.33 shows the inlet and outlet size distributions observed during

Table 3.18 Results of Cascade Impactor Tests 3 Through 8 at Centralia Power Plant (Two Stage System).

Test No./ Date	Inlet Gas Flow (SCFM)	Particle Mass Conc. (grains sdcf)		Overall Coll. Eff. (%)	Penetration (%)	Total Liquor Flow Rate (gpm)	Corona Voltage (KV)		Spray Voltage (KV)		SCA ($ft^2/scfm$)	L/G (Gal/1000 scf)	Gas Residence Time (sec.)		
		Inlet	Outlet				#1	#2	#1	#2			Corona Section	Spray Tower	Mist Eliminator
3 11/30/77	1031	0.25924	.00052	99.73	0.27	15.5	68	80	0	0	0.061	15.0	1.82	13.99	0.86
4 11/30/77	1055	0.20721	.00099	99.30	0.70	15.5	68	80	0	0	0.059	14.7	1.78	13.67	0.84
5 12/1/77	1071	0.37242	.00056	99.77	0.23	15.5	68	80	2	2	0.058	14.5	1.76	13.46	0.83
6 12/1/77	1244	0.31301	.00068	99.70	0.30	15.5	68	80	2	2	0.050	12.7	1.51	11.59	0.72
7 12/8/77	919	0.53698	.00039	99.88	0.12	16.0	68	80	10	10	0.068	17.4	2.05	15.69	0.97
8 12/14/77	1076	0.37494	.00029	99.89	0.11	15.5	68	80	0	0	0.058	14.4	1.75	13.40	0.83

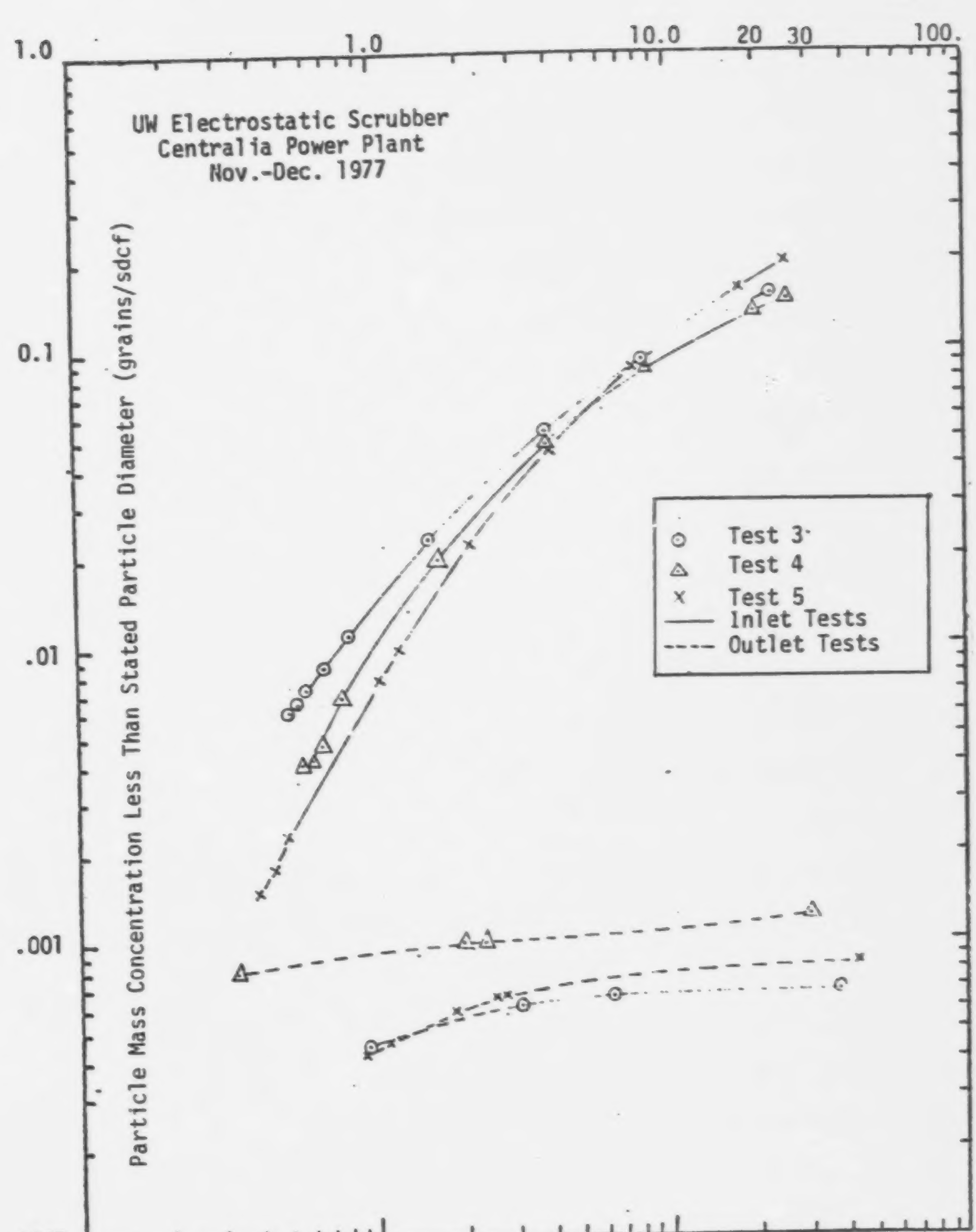
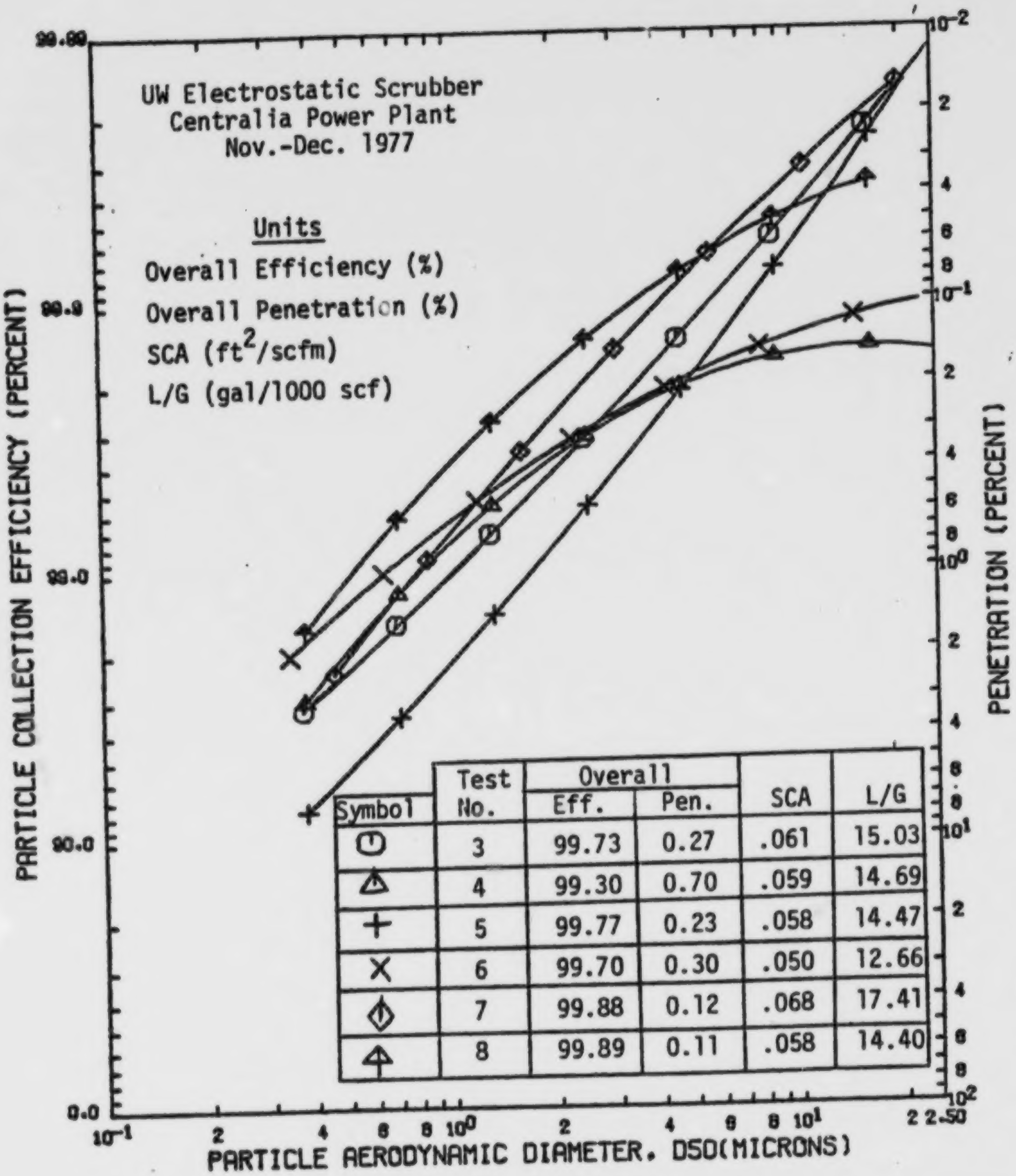


Fig. 3.33 Inlet and outlet particle size distribution for two-stage charged droplet scrubber operation.

the testing at Centralia, and Fig. 3.34 shows the observed collection efficiency as a function of particle size. Figure 3.34 data can be compared to the collection theories developed at MIT. A collection efficiency of 99% is observed for particulate of 1 μm diameter. For particles of 1 μm diameter the collection mechanism should be primarily electrostatic. Since droplets are continually sprayed into the device spray chambers charged droplet density should remain constant at a typical value such as 3×10^8 drops/m^3 [87]. A typical value of droplet charge is 3.7×10^{-14} coul/drop, and for particulate mobility is 1.5×10^{-7} m^2/Vsec. The resulting characteristic collection time of the scrubber is 5.3 sec. Since the force driving collection is constant and not dependent on the fine particulate density, an exponential collection law applies. The MIT theory predicts a device collection efficiency of 94% [88].

The University of Washington scrubber was also tested during the EPA tests with only one of the spray chambers energized. Results of these tests are presented in Table 3.19. The 10 sec residence times utilized for these tests appear to give efficiencies consistent with the NSPS standard for coal firing. The development of the University of Washington electrostatic scrubber has proceeded from the 140 cfm level in 1974 [89] to the 1500 cfm level reported here. Pilat reports that a patent on the device has been filed for and that a license for production and sales has been granted to Pollution Control Systems Corp. [90] Until a higher level of commercialization is achieved for this technology it is difficult to speculate on the eventual system capital costs. A rough guide to the cost for fiberglass corrosion-proof construction is provided by the Fluid-Ionic collector which provides roughly 2 sec of gas residence time for the high cost of \$9.20/cfm. Con-



Symbol	Test No.	Overall Eff.	Overall Pen.	SCA	L/G
○	3	99.73	0.27	.061	15.03
△	4	99.30	0.70	.059	14.69
+	5	99.77	0.23	.058	14.47
×	6	99.70	0.30	.050	12.66
◇	7	99.88	0.12	.068	17.41
⍋	8	99.89	0.11	.058	14.40

Fig. 3.34 Collection efficiency as a function of particle size for two-stage charged droplet scrubber.

Table 3.19 Results of Simultaneous In-stack Filter Tests 9-F Through 16-F at Centralia Power Plant (One Stage System).

Test No./ Date	Inlet Gas Flow (scfm)	Particle Mass Conc. (grains/sdcf)		Overall Coll. Eff. (%)	Penetration (%)	Total Liquor Flow Rate (gpm)	Corona Voltage (KV)		Spray Voltage (KV)		SCA (ft^2/scfm)	L/G (Gal/1000 scf)	Gas Residence Time (sec.)		
		Inlet	Outlet				#1	#2	#1	#2			Corona Section	Spray Tower	Mist Eliminator
9-F 2/2/78	1279	1.1390	.00095	99.89	.11	12.5	--	80	--	0	.024	9.77	0.74	7.96	0.70
10-F 2/2/78	1122	0.8584	.00116	99.80	.20	12.5	--	80	--	2	.028	11.14	0.84	9.07	0.79
11-F 2/2/78	1179	0.6774	.00077	99.84	.16	12.0	--	80	--	5	.027	10.18	0.80	8.63	0.75
12-F 2/2/78	1253	0.6920	.00088	99.82	.18	12.0	--	80	--	10	.025	9.58	0.75	8.12	0.71
13-F 2/2/78	1210	0.7530	.00101	99.82	.18	12.0	--	80	--	0	.026	9.92	0.78	8.41	0.74
14-F 2/3/78	1141	0.7650	.00115	99.79	.21	12.5	--	80	--	5	.027	10.96	0.82	8.92	0.78
15-F 2/3/78	1190	0.7110	.00085	99.83	.17	12.5	--	80	--	2	.026	10.50	0.79	8.55	0.75
16-F 2/3/78	1173	0.7030	.00113	99.77	.23	12.0	--	80	--	10	.027	10.23	0.80	8.68	0.76

sequently it would seem that the 10 sec residence time device proposed here should not be economical until its capabilities for simultaneous particulate and SO_2 collection are realized.

3. Outline of Inherent Characteristics

The Electrostatic Spray Scrubber provides adequate collection but at a relatively high cost in terms of capital expenditure, space utilization, and system energy requirements with respect to other currently available technologies. As the combined capabilities of the device for both high efficiency particulate and SO_2 control are developed these high costs might become justified and charged droplet scrubbing could become a technique that is unique for solving both of these problems in one volume.

CHAPTER III

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IV. APPLICATION OF INNOVATIVE HARDWARE TO UNITS UNDER STUDY

A. Mt. Tom, Northeast Utilities

1. Preliminary Evaluation of Innovative Technologies for Plant Requirements

Figure 4.1 illustrates the present configuration of the relatively small 1.72 sec residence time (influence time is somewhat less) ESP, fitting snugly between the plant airheater and smoke-stack. The present ESP, as discussed in Sec. IIB3, was guaranteed to provide an efficiency of 95% on coal firing by the ASME measurement technique when the unit was built in 1960. Although efficiency test results are not available, it is safe to say that if the plant were to revert to coal firing additional collector capacity would be required. Three standards are considered for this facility on coal firing:

1. The present state emission requirement of .12 lb/MMBtu.
2. An emission level of .06 lb/MMBtu consistent with the agreement reached between NEPCo and the MA DAHM.
3. A fine particle emission standard of .03 lb/MMBtu for particles smaller than 2.5 μm in size.

In view of the present uncertainties surrounding steam coal quality and availability, the emission limitations should be achievable even with the use of an inferior quality coal. The limitation provided by the NEPCo agreement for coal conversion at Brayton holds special significance for Northeast Utilities, for like New England Power, Northeast Utilities personnel have expressed serious misgivings about employing FGD technology at the Mt. Tom facility. If forced to burn coal under the provisions of FUA, Northeast Utilities could negotiate with Massachusetts officials for permission to burn coal without employing FGD, similar to the agreement

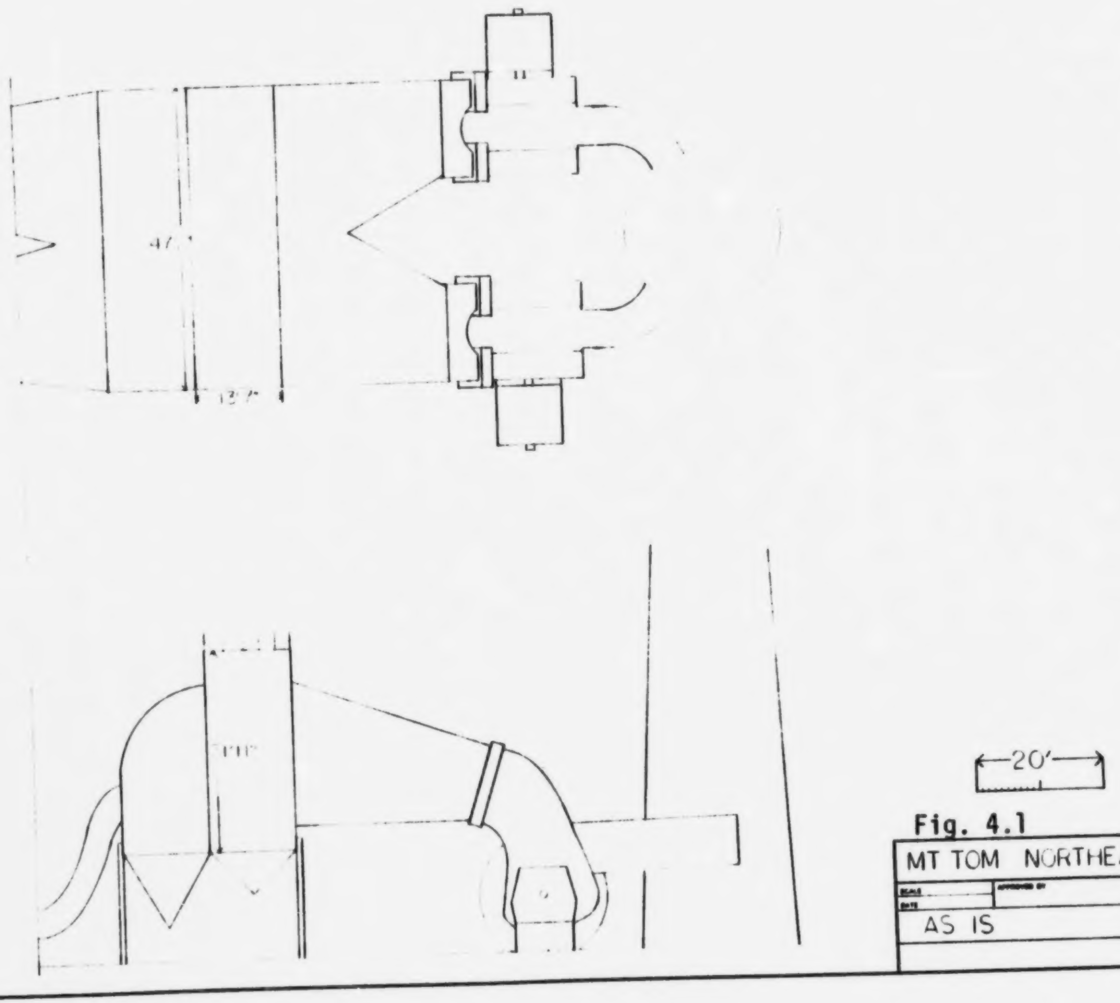


Fig. 4.1

MT TOM NORTHEAST UTIL

PZ

AS IS

negotiated for NEPCo for Brayton Point.

A somewhat worst case coal for analysis of required particulate control efficiency is 11,000 Btu/lb, 15% ash. A nominal sulfur content of 1.5% will be assumed following the guidelines established at Brayton Point. With 20% boiler ash retention, an uncontrolled emission rate of 10.91 lb/MMBtu is projected. An overall efficiency of 98.9% is required to achieve the standard of .06 lb/MMBtu, and an efficiency for fine particle of 96.6% is required to achieve the special benchmark standard (see Appendix A).

Electrofluidized Bed Agglomerator

The electrofluidized bed agglomerator is not well suited to the Mt. Tom application due to the tight spacing between the airheater and ESP inlet.

Electrofluidized Bed Collector

As shown in section 2, the electrofluidized bed collector could be fit into the available space, but would require an additional breaching of the stack at an elevated level. Without the high breaching the use of the electrofluidized bed collector would require an extensive amount of ductwork. As discussed in Chapter III, the electrofluidized bed collector can provide an efficiency adequate to achieve all three of the standards under consideration. An area of concern for the operation of the EFB collector is the high carbon levels ovserved in Mt. Tom ash samples. In addition, the use of additives for collector operation has not been demonstrated. The minimum 6" WG pressure drop demanded by the EFB collector would require the purchase of new ID fans at Mt. Tom.

Electrified Bed

The Electrified Bed configuration is well suited to installation in the exhaust plenum of the present precipitator. The single stage Electrified

Bed depicted in Sec. 2 required 3" WG of additional pressure drop, an amount which could possibly be achieved by upgrading the present ID fans. An additional possibility would be to shift the 3" WG pressure drop presently used to drive the multiclone to use across the Electrified Bed. This possibility seems remote, since the multiclone is apparently utilized to help even out the gas flow distribution through the present ESP. As discussed in Chapter III, the Electrified Bed would provide an efficiency more than adequate to achieve the three standards under consideration. High ash carbon content tends to complicate Electrified Bed operation, and would require that the rate of sand processing be accelerated.

High Intensity Ionizer

The high intensity ionizer provides an option for upgrading the present Mt. Tom precipitator, but is not particularly well suited because of the high facial velocity and small size of the present precipitator. The present precipitator employs two 6 ft long collecting electordes arranged in series. Since the high intensity ionizer requires 4' - 6' of space in the direction of flow, the employment of this device would essentially eliminate half of the precipitator collection area and null out any advantage. The position of the present multiclone rules out placement of the high intensity ionizer before the precipitator. Steve Zahos of Union Carbide stated (see Chapter III) that a precipitator with an SCA of below 100 was poor candidate for employment of the HII, and an even higher original SCA would be desirable before the removal of ESP plate area to accomodate the HII could be justified. The Mt. Tom precipitator has at full load an SCA of 75 ft^2/1000 cfm and a facial velocity of 419 fpm. Mr. Zahos considers the maximum flow capacity of the HII to be 3500 cfm/throat, with the throats spaced on 3 ft centers. Consequently, the recommended maximum facial velocity of 389 fpm for the HII would be exceeded by the Mt. Tom precipitator.

Wet Electrostatic Precipitator

Charged Droplet Scrubber

The two wet technologies considered in this study would not become attractive alternatives unless the employment of wet FGD technology was planned. The employment of FGD technology is not considered as a likely alternative for the Mt. Tom facility.

2. Equipment Layout for Selected Innovative Technologies

a. Electrofluidized Bed Collector

Figure 4.2 illustrates the application of the electrofluidized bed collector to the Mt. Tom plant. The upward gas flow required by the electrofluidized bed can be achieved through the use of fans with a vertical discharge. After passing through the electrofluidized bed gas could be ducted back down to the present stack breaching, but this would require an excessive amount of ductwork. An alternative plan would be to breach the stack at a higher level, as shown in Fig. 4.2.

The two collectors have each been divided into 16 fluidized beds of dimension 6 1/2' x 6 1/2'. Sectionalization reduces the load which must be carried by any one distributor plate, and reduces the distributor plate pressure drop required to prevent material from building up at one end of the collector. The 42.25 ft^2 sections depicted here are consistent in size with fluidized beds already employed in industrial practice. Between the distributor plates, structural members are shown to support the plates. These structural members should project above the surface of the distributor plate somewhat less than the fluidized height of the bed. In this configura-

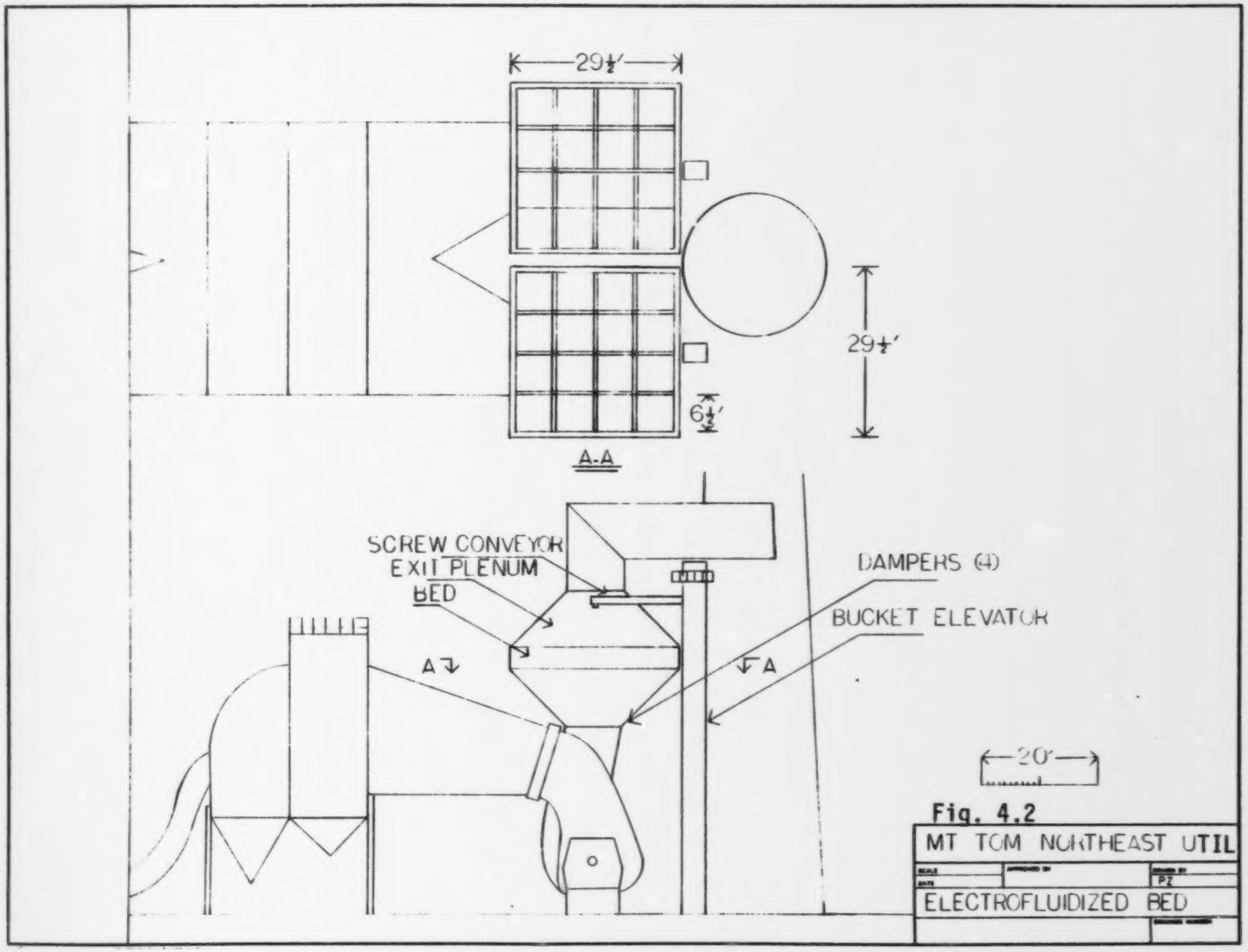

29½′
29½′
6½′
A-A
SCREW CONVEYOR
EXIT PLENUM
BED
DAMPERS (4)
BUCKET ELEVATOR
A
A
20′
MT TOM NORTHEAST UTIL
PZ
ELECTROFLUIDIZED BED

Fig. 4.2

tion only two feed points are proposed in each volume for feeding fresh granules to the collector. Material is distributed among the 16 bed sections through overflow across the structural members. Since fluidized bed height can be changed to adjust the system efficiency, the height of these dividers should be set at approximatley seven inches.

Conceptually, turndown operation can be accomodated by dividing the collector into sections which can be shut off to maintain the flow velocity during periods of reduced power production. Figure 4.2 shows a position where each collector could be partitioned into four damper controlled sections. Starting from the location of the four dampers, the collector inlet plenum must be partitioned into four regions.

The electrofluidized bed configuration shown could possibly be operated without a charging assembly, utilizing the charge imparted by the present ESP. This mode would be quite attractive considering the difficulties involved in charging flyash. If a significant percentage of the material reaching the collector has been in contact with a wall after passing by the last ESP wire, then recharging would be required.

Figure 4.2 shows elevators which feed each system, and screw conveyors which carry material horizontally to the system feed point. In the proposed configuration each collector would be fed by two screw conveyors, one behind the other. An elevator of dual bucket design could be employed to assure even distribution of material between the two screw conveyors. The conveyors would be run on a continuous basis with material feed controlled by magnetic feeders at the base of the elevators. Sensing switches such as Bindicators could be employed in the collector volume to control the feed of material.

The use of additive is required and dictates that spent particle removal should preferably take place through the individual distributor plates. Distributor plates must be allowed to expand into the structural support since they typically heat up on startup much faster than the rest of the collector structure. One pipe must be brought from each distributor plate, preferably from the center, to remove spent particles from the system. Removal of particles through the distributor plate is preferred since with the use of additive bed particles will increase in size as they collect ash, and as they enlarge they settle to the bottom of the fluidized bed. Each pipe must be fitted with a material metering device, typically either a magnetic feeder or a rotary valve. The processing of material after it leaves the active volume is dependent on the nature of the bed material utilized. Additive will typically be sprayed into the individual fluidized bed sections from the top, and the bed fluidization is exploited to spread additive around (from Alexander, see Chap. III).

Two general modes of fluidized bed collector operation have been discussed by Alexander. Sand particles can be employed as the ash collection site if reprocessing techniques are developed for removing the ash from the sand particle surface. Due to the employment of additive, this reprocessing step is complicated and should be addressed in future development efforts.

An intrinsically more attractive approach wold be to use sinters of the collected ash as collection sites. The process could be initiated with a sand seed, perhaps by filling only one of the four collector regions. After the seed is increased in size through the use of additive and the collection of ash, enlarged particles can be withdrawn and conveyed to a sintering furnace. After sintering the resulting particles can be crushed, sorted, and a fraction sent back to the collector as fresh seed. Alexander reported some problems in dealing with fluidized beds containing a wide range of particle sizes. As much as a two to one range of bed particle size is required in order to produce seed of the proper size after crushing. Larger particles tend to defluidize on the bottom of the bed and become difficult to remove.

The heat value of an oil additive can be utilized to help in the sintering process, but this will tend to be just a fraction of the heat necessary to raise the material to the required 1900°F in temperature. The ash resulting from this process would be sintered, and therefore is easier to dispose of. Of course, in the Mt. Tom application the fluidized bed is employed after the ESP and therefore should collect only a small fraction of the total boiler ash.

The Mt. Tom plant at full load has a flowrate of 424,110 acfm. Consequently, the collectors must be capable of treating 212,055 acfm each. Each collector contains a total of 676 ft^2 of distributor plate area, resulting in a bed facial velocity of 314 fpm with 100% availability. The systems are depicted with 45° sloping plenums and 19' x 19' connecting ducts with space allowed for thermal insulation. A superficial duct velocity of 2617 fpm would result from the dimensions shown. Ducting and plenum dimensions are not fundamental to the operation of the collector, and could be specified by the customer. Space is provided in the drawing for bed freeboard and the installation of additive injection equipment. The fluidized bed itself should not extend more than 10" in height.

b. Electrified Bed

Figure 4.3 illustrates the installation of the Electrified Bed in the exit plenum of the Mt. Tom precipitator. The system depicted is a one-

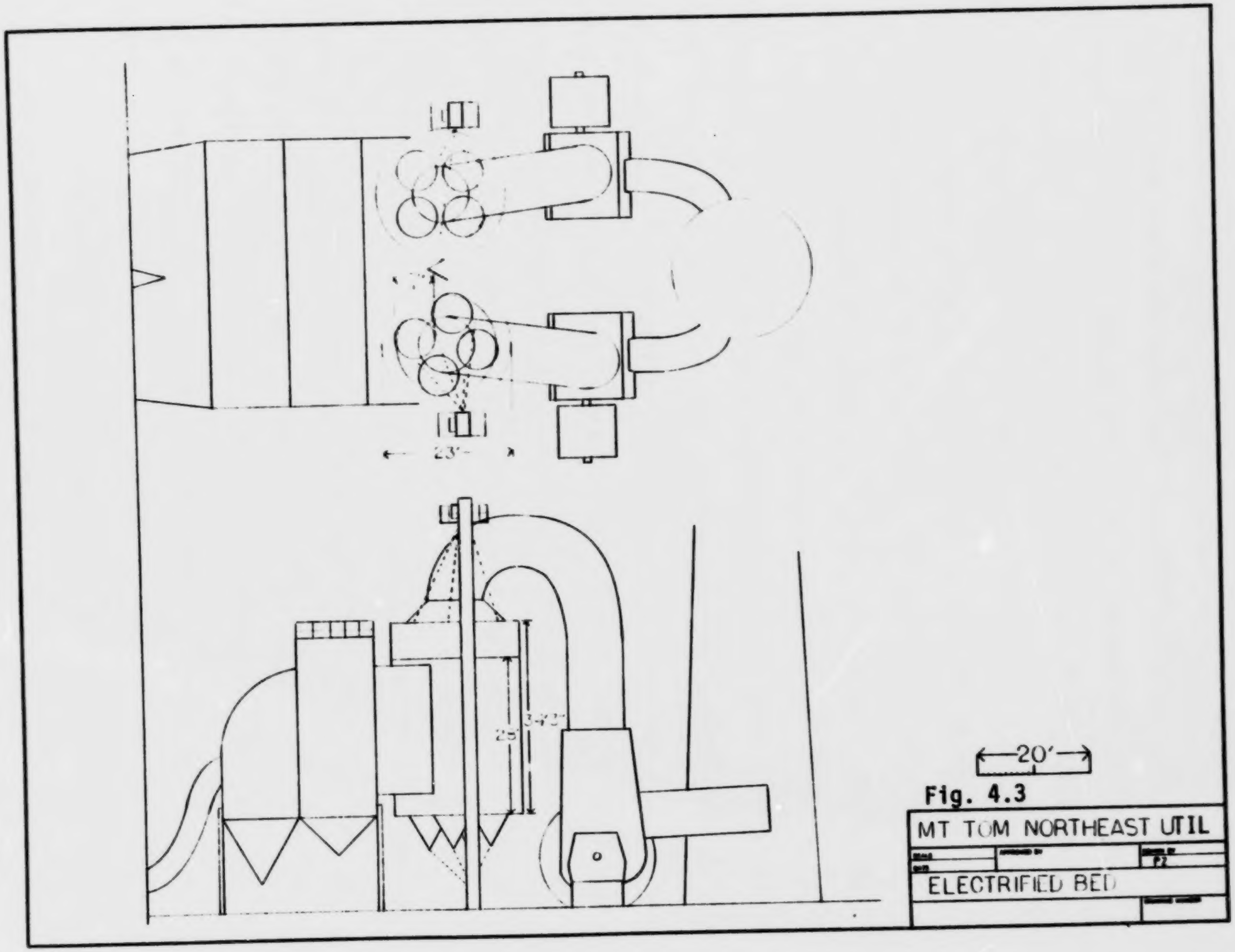

23'
25'
34'2"
20'
MT TOM NORTHEAST UTIL
P2
ELECTRIFIED BED

Fig. 4.3

stage collector, which takes advantage of the present ESP as a charger and roughing filter. The adequacy of particle charge in the ESP exit plenum has not yet been established. Large 7' tube diameters have been employed to reduce system complexity and improve accessibility. A smaller system volume would result from the use of a larger number of smaller tubes. As shown in Fig. 4.3, the Electrified Bed can be installed at Mt. Tom without changing the orientation of the fan inlet and outlet boxes. Gas flows first into the cylindrical 23' inlet plenum of the device, then passes through the 3" to 5" deep panel bed filters, and exhausts through the center of the 7' diameter cylinders to a gas plenum atop the collector. Sand slowly flows down through the dylindrical panel bed filters, metered from below the hopper of each cylinder by a magnetic vibrating feeder. Sand then passes to a reprocessing stage (see Fig. 3.14), to the elevator, and back to the top of the system. From each elevator sand can be metered to the four collectors in an overflow mode, with a distribution box located at the elevator discharge. One of the five sand flow pipes from each elevator would have to pass through the gas exit duct. Sand flow pipes will typically be from 6" to 8" in diameter.

The configuration depicted in Fig. 4.3 provides 2,462 ft^2 of facial area per collector, or 4.926 ft^2 to meet the requirements of the entire plant. At a full load gas flow of 424,110 acfm the panel bed facial velocity of 86 fpm results in less than a 3" WG pressure drop across the collector. As plant operation is turned down and gas flow decreases, Electrified Bed pressure drop decreases and efficiency increases.

Figure 3.14 illustrates the reprocessing loop utilized by EFB, Inc. to clean flyash laden granules. In the Electrified Bed particle abrasion is minimized and consequently ash remains stuck to the surface of the bed particles without the use of an additive. After leaving the vibrating screen feeder located at the bottom of the panel bed lower hopper flyash laden particles are fed to a small wildly fluidized bed. The abrasion of the fluidized bed quickly entrains ash in the fluidization gas stream which conveys it to an ash storage silo. If the ash contains high levels of carbon, crushed glass should be employed as the bed collection material to facilitate thorough cleaning. Cleaned sand overflowing from the fluidized bed passes directly into the elevator inlet, and is conveyed to sand storage at the top of the collector. The sand processing rate is set by the vibrating magnetic feeder located beneath the lower hopper of each cylindrical collector. EFB, Inc. found during the GM tests (Chapt. III) that a secondary air flow ranging from between 3% to 5% of the primary air flow was sufficient for continuous operation on coal emissions.

B. Middletown 3, Northeast Utilities

1. Preliminary Evaluation of Innovative Technologies for Plant Requirements

Figure 4.4 illustrates the present 3.16 sec influence time ESP operating on the Middletown 3 station of Northeast Utilities. With a 9" duct width this precipitator features an SCA of 141.5 ft^2/1000 cfm and a guaranteed efficiency on coal firing of 98.5%. As discussed in Chap. II, this efficiency was apparently not achieved. The efficiency of the collector is apparently not high enough to achieve the present Connecticut emission standard of 0.2 lb/MMBtu. The Gibbs and Hill study on the Middletown plant discussed in Chap. II suggests that in order to achieve the Connecticut standard and leave a margin for safety and fuel variation the exist-

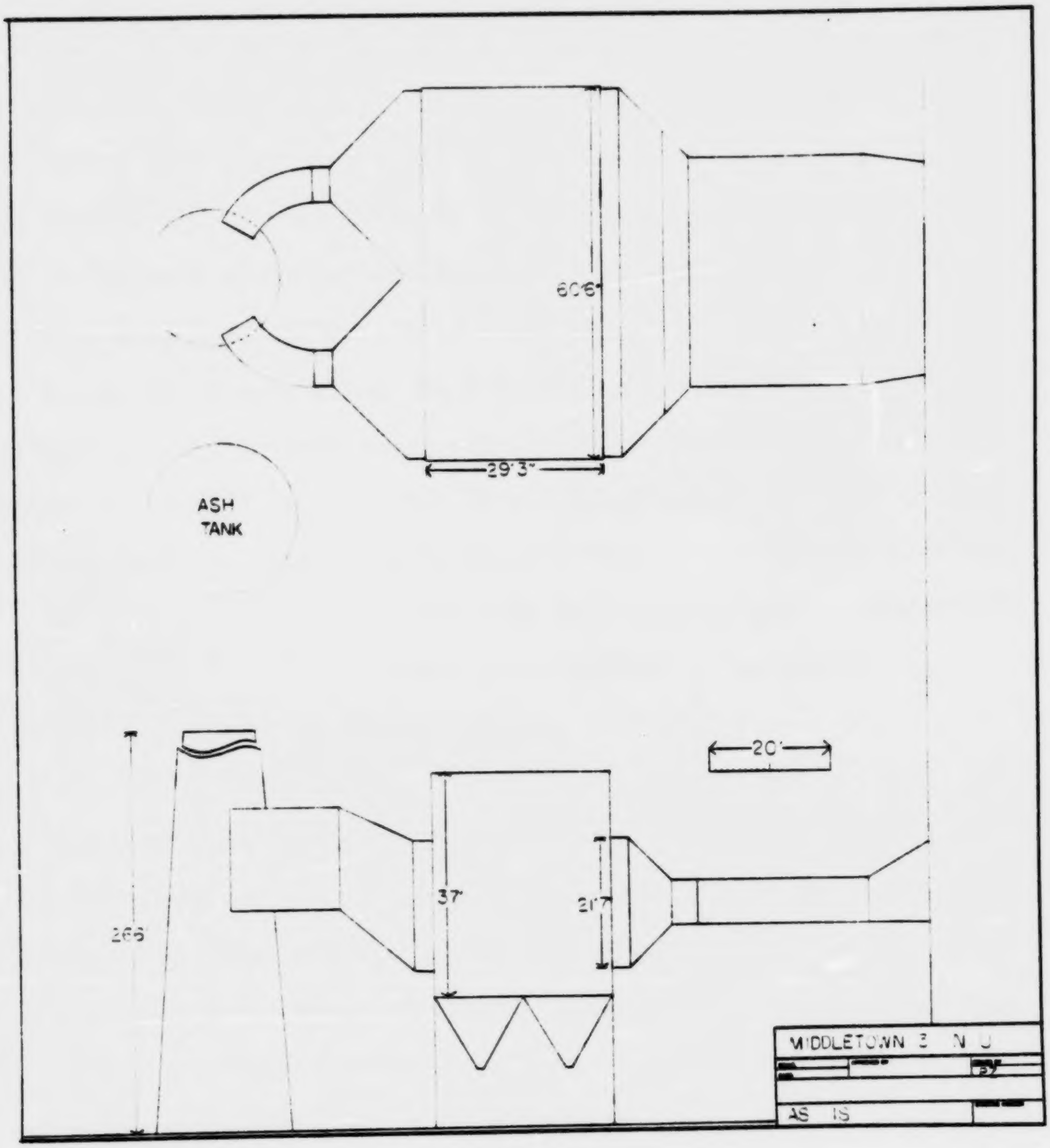

60'6"
29'3"
ASH
TANK
20'
266'
37'
21'7"
MIDDLETOWN 3 N U
AS IS

Fig. 4.4

ing equipment should be upgraded to 99% efficiency. The Gibbs and Hill estimate is based on 12,500 Btu/lb coal and 10% ash. Assuming a 40% boiler ash retention for the cyclone fired boiler an efficiency of 96% should be required. In order to achieve the suggested 99% efficiency Gibbs and Hill recommends that the present 24' treatment length ESP be supplemented by an additional ESP of equal size. The present ESP is designed for an unusually high gas superficial velocity of 456 fpm. The conservatism of Gibbs and Hill seems warranted in view of the present TSP noncompliance status for many area of Connecticut.

Due to the difficulties involved with burning coal in the Middletown 3 boiler, retrofit hardware is primarily evaluated with respect to upgrading the present efficiency on oil firing. Unfortunately, test results of the present boiler emission rate or ESP efficiency on oil firing are not available. Data reported in Table 2.3 for the modern Mystic 7 boiler shows uncontrolled emissions on oil firing ranging from .05 to .10 lb/MMBtu. Mystic 7 burns 1%S oil while Middletown 3 burns 0.5%S oil. Size data from Mystic 7 (Fig. 2.3) indicates that approximately 30% of the uncontrolled material is fine (smaller than 2.5μm aerodynamic diameter). Taking the Mystic 7 emissions as representative of oil units, it can be seen that Middletown 3 is easily in compliance with the Connecticut state standard of .2 lb/MMBtu, and probably is in compliance with the Brayton Point standard of .08 lb/MMBtu. On an uncontrolled basis, the unit is marginally in compliance with the benchmark standard of .03 lb/MMBtu for fine particles. Assuming that the present ESP is not effective in controlling fine particles, retrofit hardware might be desirable to provide a wider margin of safety.

Electrofluidized Bed Collector

Electrofluidized Bed Agglomerator

Although the tight spacing between the present ESP and stack does not provide sufficient spacing for the electrofluidized bed collector, the agglomerator can be installed in the ducting which stretches across the FD fan house. As shown in section 2, this installation is somewhat complicated by the roof of the fan building being on the same level as the bottom of the inlet to the ESP. The present FD fans can provide, according to plant personnel, as much as 3" WG to power air pollution control equipment. Although this much pressure is not sufficient for operation of the electrofluidized bed, ID fans would be required. Northeast Utilities personnel have stated that it is often desirable to install ID fans and convert pressurized units to balanced draft. As discussed in Chap. III both the electrofluidized bed and the Electrified Bed are effective at the collection of fine particles and would provide a wide margin of safety in achieving the benchmark standard.

Electrified Bed

A one stage Electrified Bed collector can be installed in the exit plenums of the present ESP. The 3" WG extra fan power availableis sufficient for operation of the one-stage collector. The installation of a one-stage Electrified Bed collector after the present ESP takes advantage of the ESP as a roughing filter and charger.

High Intensity Ionizer

Due to the high facial velocities utilized in the Middletown 3 precipitator the high intensity ionizer cannot be utilized as a retrofit pollution control device. The high intensity ionizer cannot operate effectively on ESPs with facial velocities of higher than 389 fpm.

Wet Electrostatic Precipitator

Charged Droplet Scrubber

The two wet technologies considered in this study would not become attractive alternatives for Middletown 3 unless the employment of wet FGD technology was planned. The employment of FGD technology is not considered as a likely alternative for Middletown 3.

2. Equipment Layout for Selected Innovative Technologies

a. Electrofluidized Bed Agglomerator

Figure 4.5 illustrates the application of the electrofluidized bed agglomerator to the Middletown 3 facility. The agglomerator has been divided into three vertical sections which extend the entire width of the ESP. Note that the high roof of the fan building has prevented the placement of the agglomerator directly adjacent to the ESP inlet because of the requirement for vertical flow through the collector. The agglomerator as shown in Fig. 4.5 is designed for a superficial velocity of 325 fpm with approximately 10% of the bed area reserved for structural support. Dampers are provided to permit turndown operation at flows well under 1/3 of full capacity. Since the collector is operated in an agglomerator mode, continuous equipment is not required for feeding bed material to the system. An elevator could be provided to charge the system, or in the event of overhaul the system could be refilled with a hired crane.

Two components not shown but important for agglomerator operation are ionizing elements and the equipment necessary to spray additive into the bed. Ionizing elements such as the high intensity ionizer can be located anywhere before the bed sections, either directly below the distributor plate or in the ducting leading to the system. For oil firing placement

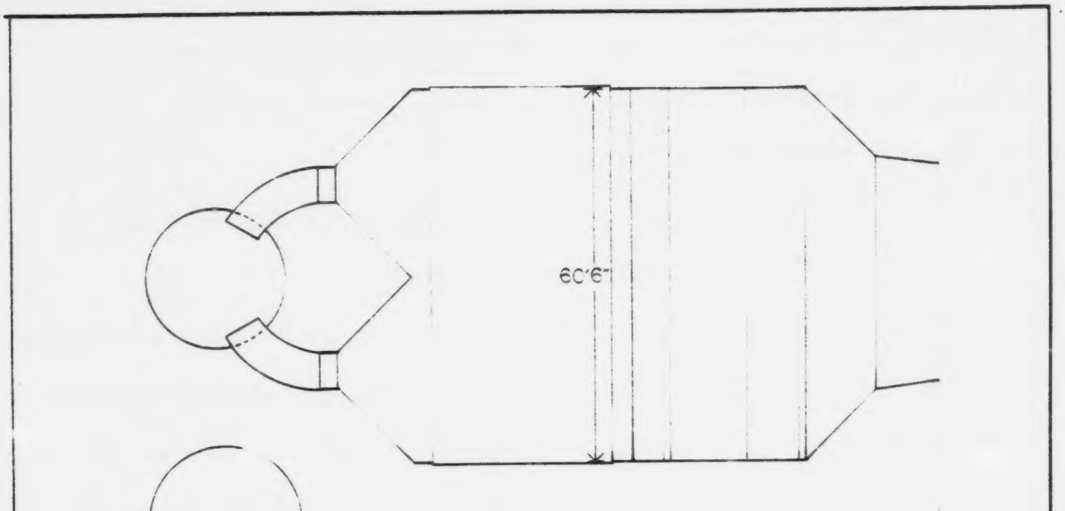

60'6"
20'
12½'
BEDS(3)
DAMPERS
MIDDLETOWN 3 N U
ELECTROFLUIDIZED BED

Fig. 4.5

in the ducting is preferred because of the smaller area and greater accessibility. For coal firing elements should be placed as close to the distributor plate as possible. Flyash precipitating to the wall before the distributor plate will blow off uncharged and reduce the effectiveness of the agglomerator. Self precipitation is not as important of a problem for the lower loadings typical of oil ash or for flyash loadings observed after an ESP. Additive will typically be sprayed from the top into a fluidized bed. Alexander found that fuel oil could serve as an effective additive for an agglomerator.

In agglomerator operation particles from the gas, including the fine particles typical of oil firing, are collected on and stuck by additive to the surface of the bed sand particles. Through the abrasive action of the fluidized bed pollutant particles are scraped off of the surface of the sand particles, but in large clumps and more easily collected by the downstream ESP. Consequently the agglomerator itself has no efficiency but it can serve to significantly enhance the effectiveness of collection.

b. Electrified Bed

Figure 4.6 illustrates the installation of the Electrified Bed in the exit plenum of the Middletown 3 precipitator. The system depicted is a one-stage collector, which takes advantage of the present ESP as a charger and roughing filter. Large 8' tube diameters have been employed to reduce system complexity and improve accessibility. A smaller system volume would result from the use of a larger number of smaller tubes. As shown in Fig. 4.6, the Electrified Bed can be installed at Middletown 3 with a minimum requirement for extra ducting if a new breaching of the stack can be made. If breaching the stack at a higher point is not possible, the present breaching can be utilized by moving the cylindrical collectors outward. This

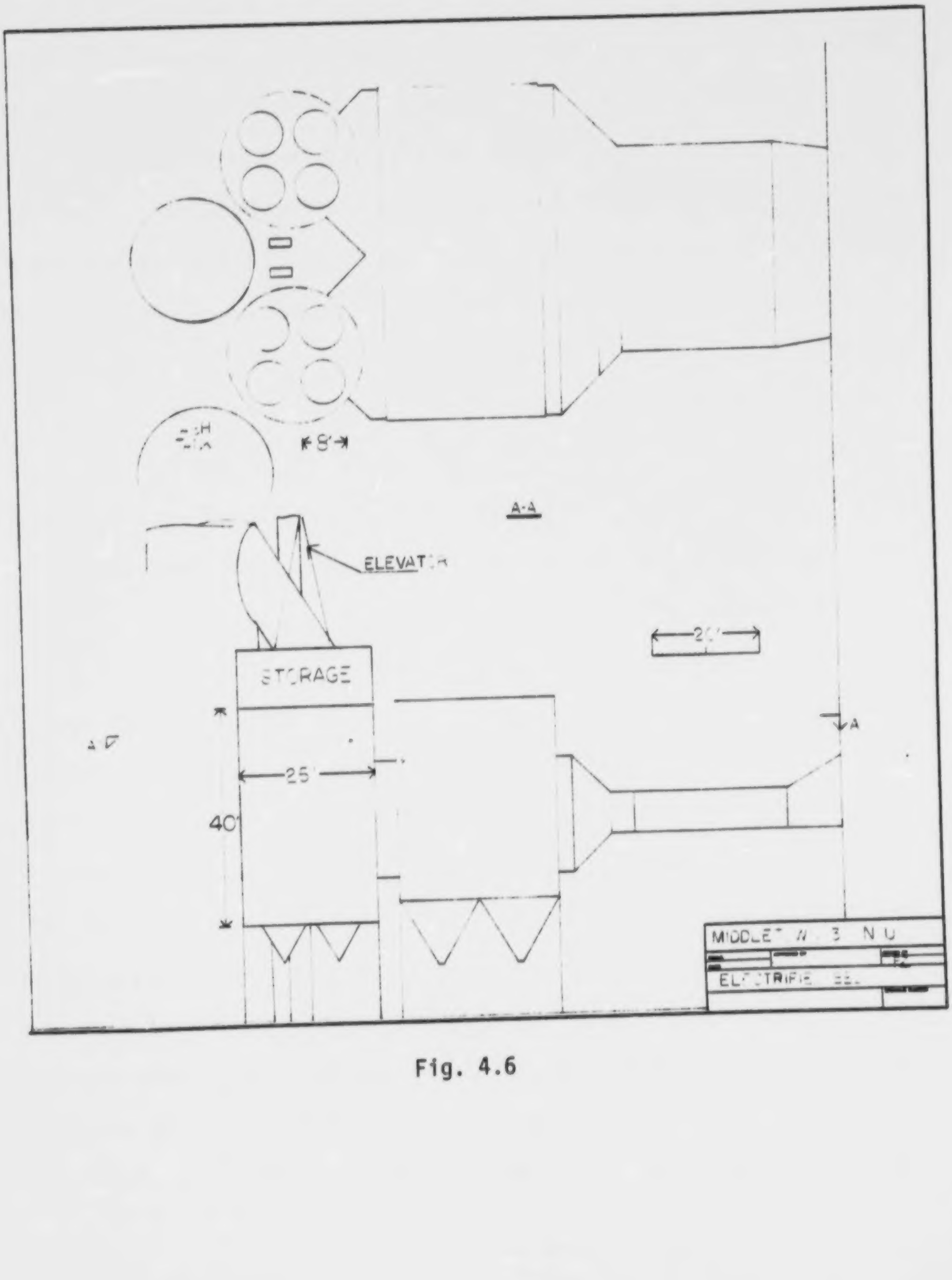

8'
A-A
ELEVATOR
20'
STORAGE
A
A
25'
40'
MIDDLET
ELECTRIFIE

Fig. 4.6

movement would in all probability require the movement of the ash tank. Gas flows first into the cylindrical 25' inlet plenum of the device, then passes through the 3" to 5" deep panel bed filters, and exhausts through the center of the 8' diameter cylinders to a gas exit plenum atop the collector. Sand slowly flows down through the cylindrical panel bed filters, metered from below the hopper of each cylinder by a magnetic vibrating feeder. Sand then passes to a reprocessing stage (see Fig. 3.14), to the elevator, and finally back to the top of the system. From each elevator sand can be metered to the four collectors in an overflow mode, with a distribution box located at the elevator discharge.

The configuration depicted in Fig. 4.6 provides 4021 ft^2 of facial area per collector, or 8042 ft^2 to meet the requirements of the entire plant. At a full load gas flow of 636,000 acfm the panel bed facial velocity of 79 fpm results in a pressure loss of less than 3" WG. This amount of pressure loss is available from the reserve of the present FD fans. As plant operation is turned down and gas flow decreases, Electrified Bed pressure drop decreases and efficiency increases.

Figure 3.14 illustrates the reprocessing loop utilized by EFB, Inc. to clean flyash laden granules. The effectiveness of this process was demonstrated on high carbon ash generated in a stoker fired boiler operating on reduced load, and during startup and shutdown operations. Although the system has not been tested on oil emissions, the successful operation on high carbon flyash suggests that operation on oil emissions will also be effective. The Electrified Bed reprocessing loop has been discussed in both Section IIIC and Section IVA.

C. Mystic 7, Boston Edison

1. Preliminary Evaluation of Innovative Technologies for Plant Requirements

Figure 4.7 shows a plan view of the present 7.7 sec residence time ESP. The present ESP, as discussed in Sec. IIB1, was guaranteed to provide an efficiency of greater than 95% (depending on the unit emission rate) on oil emissions. The measured emission rate of the unit on 1%S oil firing has been consistently below the .03 lb/MMBtu new source performance standard, and consequently is in compliance with the benchmark fine particle standard and any of the particulate efficiency standards discussed in this study. The Mystic 7 boiler, in operation since 1975, is equipped for oil firing only.

If a 600 MW unit such as Mystic 7 was built today, due to the Fuel Use Act and the present structure of fuel prices, coal firing would be employed. In addition, a new unit would fall under the provisions of the .03 lb/MMBtu new source performance standard. In this study for the Mystic 7 unit innovative control systems are designed into the space of the present ESP. Similar to the present ESP, innovative hardware is designed to treat a total of 1.49×10^6 acfm of flue gas. Consistent with the new source performance standard, strategies are devised to achieve compliance with the sulfur oxides emission standard as well as the particulate emissions standard. The standard for NO_x emission is not addressed in this analysis, since compliance is achieved through combustion modifications.

The present ESP on Mystic 7 is designed for the collection of oil emissions. This ESP provides an SCA of 340 ft^2/1000 acfm, a size considered adequate by the EPA for achieving the new source performance standard when burning high sulfur coals. The EPA suggests that a 1000 ft^2/1000 acfm will achieve the standard when burning even the most difficult low sulfur

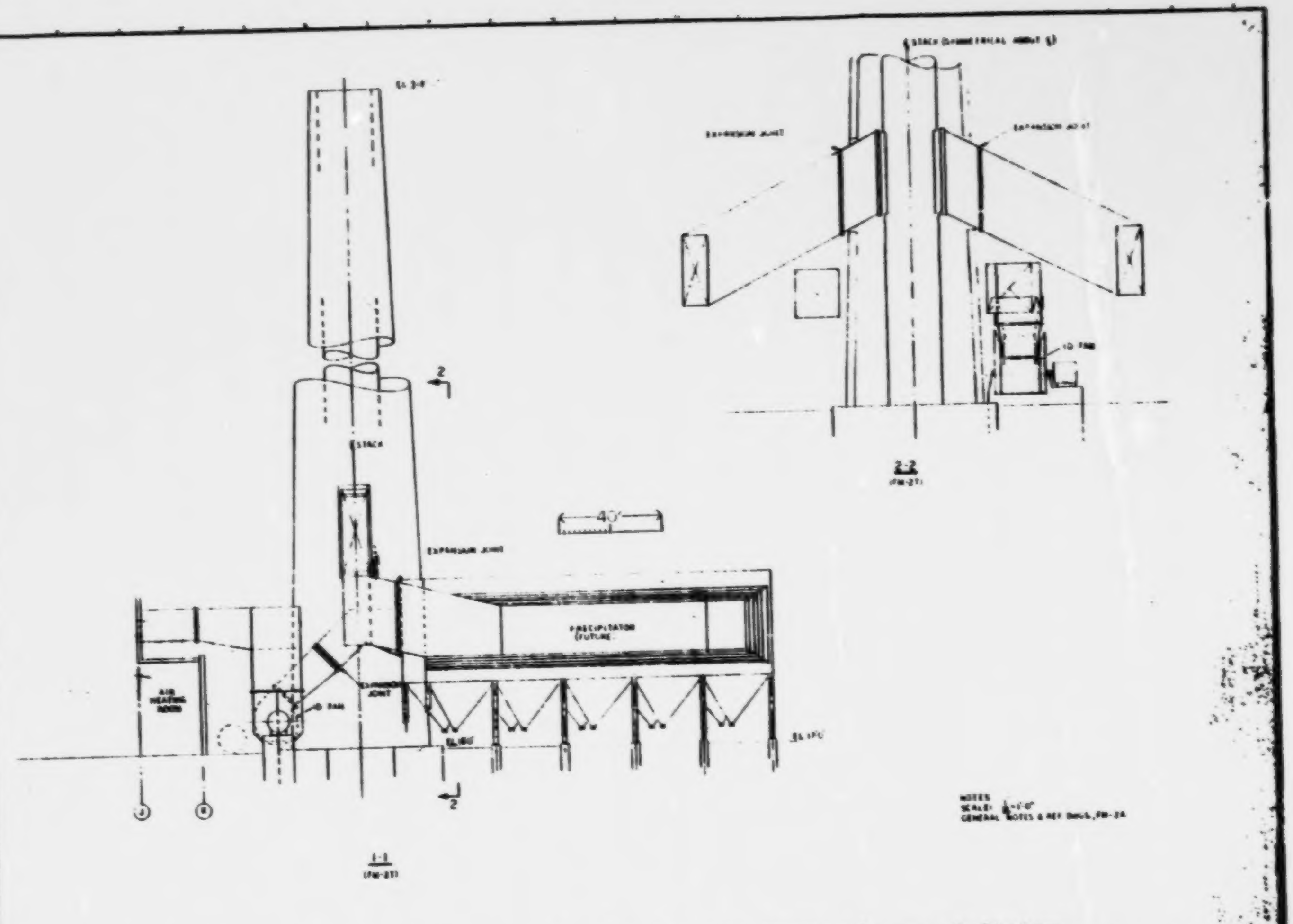

STACK (SYMMETRICAL ABOUT ℄)
EXPANSION JOINT
EXPANSION JOINT
ID FAN
2-2
(FM-27)
2
STACK
EXPANSION JOINT
40'
AIR HEATING ROOM
ID FAN
EXPANSION JOINT
PRECIPITATOR (FUTURE)
2
1-1
(FM-27)
NOTES
SCALE:
GENERAL NOTES & REF DWGS. FM-24

Fig. 4.7 Mystic 7, Boston Edison Co. As is with electrostatic precipitator.

coals (see Sec. 13). Consequently, the present ESP provides a reference point for the evaluation of the size of innovative technologies for both oil and coal emissions.

The new source performance standard permits the burning of anthracite coal with SO_2 emissions of up to 1.2 lb/MMBtu and no minimum percentage reduction in emissions required. This emission limit is achieved by anthracite coal with a sulfur content of less than .77%, a common characteristic of anthracite coals. Since anthracite coal was once mined in New England, this standard is of special interest to local utilities. Meta-anthracite coal found in Newport, Rhode Island has a sulfur content of 0.3%, an ash content of 18.9%, and a Btu value of 9,310 Btu/lb. [1] This coal has an uncontrolled SO_2 emission rate of 0.64 lb/MMBtu (well below the NSPS standard) and an uncontrolled particulate emission level of 16.2 lb/MMBtu (assuming a four to one ratio of flyash to bottom ash). A particulate collection efficiency of 99.82% is required to achieve the NSPS standard. As discussed in Chapter III this level of collection efficiency can be achieved by the electrofluidized bed and the Electrified Bed.

Electrofluidized Bed Collector

A possible configuration for utilization of the electrofluidized bed would be as a two-stage collector, with charging elements placed between the two stages. This configuration is preferred for several reasons:

1. The effect of gas bypassing is minimized through staging
2. Charging can be performed with less difficulty under the conditions of the lower ash loadings following the first stage collector
3. Since the second stage bed lies directly above the first stage

bed the problems of material handling are only slightly greater for the two beds than one

4. The flat wafer-like shape of the fluidized bed implies that the employment of a second bed requires only a small incremental increase in collector volume.

Both stages of the fluidized bed would be operated in a collector mode, that is, an additive would be employed to promote the sticking of pollutant to the bed material until bed material can be removed and regenerated. An important area for the further development of the electrofluidized bed is the identification of suitable additives. The high intensity ionizer would provide an effective charging system for employment between the two fluidized bed stages.

Electrified Bed

The Electrified Bed can be employed in either a one-stage or two stage mode to achieve the new source performance standard when burning anthracite coal. If a one-stage collector is employed, a mechanical prefilter is required to enhance the effectiveness of the charging elements which must precede the final high efficiency stage. As described in Section 2, both the one-stage and two-stage collectors occupy the same volume due to the smaller tube sizes employed in a two-stage collector. The one-stage collector preceded by a multiclone is shown for the anthracite application, while the two-stage collector is shown in conjunction with SO_2 collection. The high intensity ionizer would provide a suitable ionizing system for employment with the one-stage Electrified Bed, but is not suitable with the two-stage collector which employs ionizing elements in the center of the collecting tubes.

For the anthracite application where SO_2 collection is not required wet collection is undesirable due to the material corrosion problems encountered and the expense of stack reheat. The two wet systems in this study are considering in cases where SO_2 collection is called for.

Bituminous coal is the fuel which is primarily considered for employment in New England. Bituminous coal is available to New England powerplants from mines in Pennsylvania and West Virginia. As described in Section IB3 which describes the new source performance standards, a new facility must employ SO_2 scrubbing when burning bituminous coal. For emissions of up to .6 lb/MMBtu, a minimum 70% reduction in potential SO_2 emissions must be achieved (as determined by the coal sulfur content as mined). For emissions greater than 0.6 lb/MMBtu, a 90% reduction in potential SO_2 emissions must be achieved, up to a maximum allowed emission level of 1.2 lb/MMBtu. As discussed in Section IB3, the 70% reduction level was allowed to facilitate the employment of dry sorbent collection schemes. The Electrified Bed will hold collected solids in contact with the flue gas stream for a period of up to several hours as determined by the bed rotation speed. This contacting of solids with the gas stream is favorable for the utilization of dry collection, since the ducting leading to the dust collector generally does not provide sufficient residence time and/or mass transfer for complete utilization of the sorbent material. A dry SO_2 collection system in conjunction with the Electrified Bed is illustrated in Sec. 2. In lieu of further development work on additive cost and properties in the electrofluidized bed collector, it is difficult to predict whether the electrofluidized bed would be desirable for employment in conjunction with dry sorbent collection.

Both a baghouse and an ESP can be employed in conjunction with the dry SO_2 collection technology. Several dry collection systems are currently under construction, and data from these projects was utilized to size the spray dryers depicted in Section 2 for use with the Electrified Bed. For more information on dry collection processes several references can be consulted [2,3,4,5,6].

In revising the NSPS SO_2 standard from a uniform SO_2 reduction of 90% to the two part standard just discussed, EPA considered the relative costs of dry and wet collection as a function of coal alkalinity and the required SO_2 reduction level. Coal alkalinity plays a key role in the relative economics of dry and wet technologies, since a substantial percentage of the alkaline material required for SO_2 collection in both dry and wet schemes is often contained in the coal ash. Operating, capital, and maintenance (not including sorbent) costs are higher for a wet scrubber than for a dry scrubber, but reagent is more efficiently utilized so that sorbent costs are less. Consequently, the conditions of low sulfur, low required collection efficiency, and high coal alkilinity favor the employment of the dry scrubber technology. The EPA concluded that the dry scrubber technology would be economic for alkaline coals with collection efficiencies as high as 85%, for non-alkaline coals at 70% collection efficiency for coals with SO_2 emission potentials as high as 3.7 lb SO_2/MMBtu, and for non-alkaline coals at 80% collection efficiency for coals with SO_2 emission potentials as high as 3 lb SO_2/MMBtu [6]. The following table lists the equivalent percentage coal sulfur content for both a high and a low coal heating value. This data was incorporated into the final NSPS standard, which requires an SO_2 collection efficiency of 80% for coal with an SO_2 emission potential of 3 lb/MMBtu. The EPA intended that dry technologies be competitive with wet technologies for the nation's large reserves of non-alkaline coals. Consequently, for

Coal SO_2 Emission Rate (lb SO_2/MMBtu)	3.7	3
For coal heat value 8000 Btu/lb		
coal sulfur content (%)	1.48%	1.2%
For coal heat value 12,000 Btu/lb		
coal sulfur content (%)	2.22%	1.8%

non-alkaline bituminous coal with a heating value of 12,000 Btu/lb 1.8%S content is the upper limit (according the EPA) for which dry scrubber technology is competitive. Coals with sulfur content both above and below this cutoff point are available to utilities in New England. Economic analysis, depending on the relative fuel costs, would determine whether a utility would employ the low sulfur, dry collection approach or the high sulfur wet collection approach.

Charged Droplet Scrubber

Wet SO_2 collection has been in practice for several years, most notably in Japan. SO_2 collection systems as presently employed often perform both particulate and SO_2 control in one volume. This option is inherently attractive, but wet scrubbers are not able to readily achieve the recently promulgated .03 lb/MMBtu NSPS particulate standard. To achieve the NSPS standard either separate particulate collection must be employed, conventionally either a baghouse or an ESP, or the efficiency of the wet scrubber must be enhanced. The charged droplet scrubber has been demonstrated by Pilat as an effective scheme for achieving the .03 lb/MMBtu NSPS standard on coal emissions. The application of the charged droplet scrubber (CDS) to the Mystic 7 plant is explored in Section 2.

The application of conventional wet scrubbing technology in tandem with a separate particulate collection device is not explored in this chapter, but extensive information is available elsewhere. The EPA has extensively documented the present state of wet SO_2 scrubber technology [7,8]. Wet SO_2 scrubbers could be used in tandem with the electrofluidized bed and Electrified Bed collectors described in this section for use on anthracite coal.

Wet Electrostatic Precipitator

The wet electrostatic precipitator is a device which is well suited for combined SO_2 and particulate collection. The Fluid-Ionics collector is presently undergoing tests in which SO_2 collection is performed in the cyclonic wet scrubber which comprises the lower half of the collector volume. The Fluid-Ionics configuration is appropriate for obtaining the present state emission standard on coal firing, but is not high enough in particulate efficiency to achieve the NSPS .03 lb/MMBtu standard. This can be seen from the analysis in Appendix A which reports that for two case study coals the following ESP parameters are required (see Table A.2):

Case Study Coal	$\tau_{res} E^2 \varepsilon_0/s\mu$ (1/μm)
A	2.2
B	3.64

The following parameter values can be substituted to calculate the required ESP residence time.

$E = 4.2 \times 10^5$ V/m (from Fluid-Ionics)

$\varepsilon_0 = 8.85 \times 10^{-12}$ f/m

$s = .076$ m (from Fluid-Ionics)

$\mu = 2.0 \times 10^{-5}$ kg/m·sec (at 140°F, atm. pressure)

Substituting these parameters yields the required ESP residence times listed below along with the equivalent flow capacity for the 720 ft^3 Fluid-Ionic collection module. Note that this calculation is based on the Deutsch equation which represents the theoretical maximum ESP collection efficiency, a maximum that can be closely approached in a wet wall collector. Although the scrubber incorporated into the Fluid-Ionic collector will contribute to the overall efficiency, its effectiveness is low for the small particles escaping ESP collection (see Appendix A).

Case Study Coal	Required Residence Time To Achieve NSPS	Equivalent Module Flow Capacity
A	2.14 sec	20,187 acfm
B	3.54 sec	12,203 acfm

Fluid-Ionics suggests that their modules can be employed at flow velocities ranging from 30,000 acfm to 100,000 acfm. It is unclear whether the lower limit is set by fluid mechanics or by economics. In any event, the economic limitation is clear. At a sale price of $350,000/module case study A coal would require $17/acfm for particulate control hardware and case study B coal would require an expense of $29/acfm. These prices are significantly higher than those commonly paid by utilities for particulate control hardware (see Chapt. V). Outfitting the modules for SO_2 collection would increase the cost even more. The use of the Fluid-Ionics collector is explored in the New Boston 2 application where lower control efficiencies are mandated.

Electrostatically Enhanced Bag Filter

The electrostatically enhanced bag filter (EEBF) is a system which in the future will receive considerable attention as an approach for solving utility particulate problems. As discussed in Chapter III, the EEBF is primarily suited for new applications since it is large and fully capable of providing a low stack emission level wihtout the assistance of another particulate control device in series. Although there is much question as to whether the EEBF is a significant advancement over conventional bag filter technology except in the area of collection efficiency, there is no question that on new installations bag filters are growing in popularity. Since conventional bag filters display efficiencies high enough to meet the NSPS and benchmark standards on coal firing, the efficiency enhancement of electrostatic charging is welcome but is of marginal benefit. In addition, electrostatic charging provides a reduction in system pressure loss. Figure 3.22 shows that with an air filtration rate of 8.25 acfm/ft^2, a bag pressure drop of 2" WG results. In order to distribute flow across the large collection system required to treat utility emissions an additional system pressure loss of at least 1" WG should be required. Consequently an overall system pressure loss of 3" WG will result.

In order to achieve SO_2 collection the EEBF could be coupled with a dry SO_2 scurbbing system similar to that described for use with the Electrified Bed. The application of the EEBF to the Mystic 7 application is duscussed in more detail in Sec. 2.

2. Equipment Layout for Selected Innovative Technologies

a. Electrofluidized Bed Collector

Figure 4.8 illustrates the application of a 2-stage electrofluidized bed collector in the place of the present electrostatic precipitator. The two-stage configuration is preferred for the reasons listed in Section 1, and was observed to provide efficiencies well in excess of that required to achieve the NSPS by Alexander. Sufficient space has been provided between the two stages to allow incorporation of an ionizer such as the high intensity ionizer. Since this collector is designed for use on a new unit, a special opportunity is provided for exploring the self agglomerating mode described by Alexander [9]. A new boiler could be provided with the apparatus required for the sintering of ash required by this mode.

Alexander reports that at room temperature bed particles can be more than doubled in weight through the collection of ash and the use of an additive (not yet demonstrated at stack temperatures) [10]. Following Alexander, a conservative methodology for estimating the parameters of the self agglomerating mode is to estimate that bed particles have doubled their weight with ash when they are withdrawn from the bed. For the 600 MW unit studied here burning 12,000 Btu/lb coal with a 12.5% ash content (80% of which becomes flyash) and a boiler heat rate of 9183 Btu/kW·hr (from Mystic 7), a total of 4.6×10^4 lb/hr of flyash is generated. Alexander reports that sintering adequate for this application requires that particles be heated to 1900°F for 30 minutes. Papers on the sintering process point to a strong dependence of sintering time on temperature, but regulations governing NO_x generation preclude boiler temperatures much higher than those required here [11,12,13,14,15]. It has been reported that the bulk density of sin-

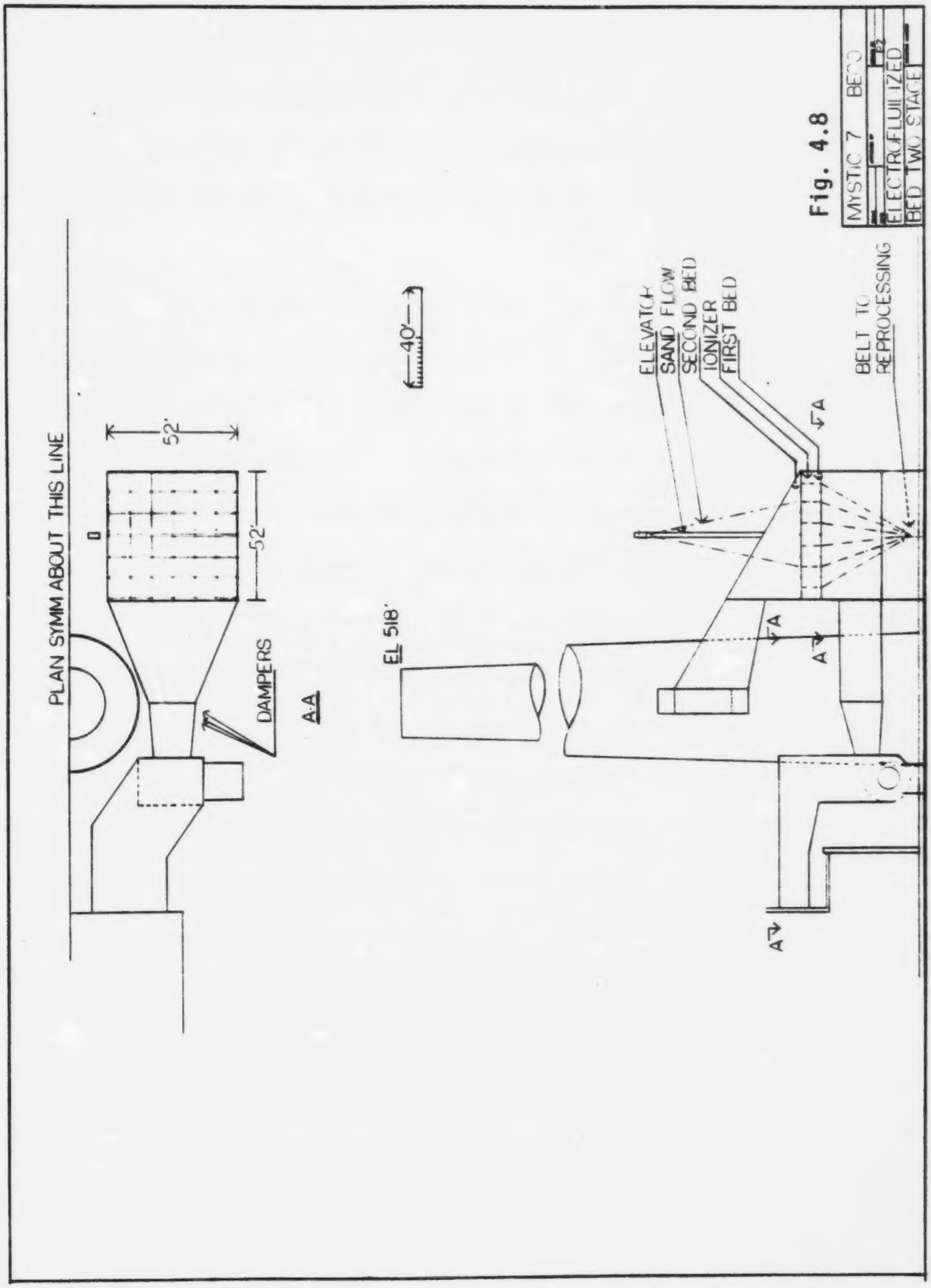

PLAN SYMM ABOUT THIS LINE
52'
52'
DAMPERS
A-A
A
EL 518'
40'
ELEVATOR
SAND FLOW
SECOND BED
IONIZER
FIRST BED
A
A
A
BELT TO
REPROCESSING
MYSTIC 7 BECO
ELECTROFLUIDIZED
BED TWO STAGE

Fig. 4.8

tered ash is approximately 50 lb/ft^3 [11]. Consequently, assuming that ash must be accompanied on a one to one basis with collection substrate, a total volume of 920 ft^3 must be in sinter to accomodate the production of the 600 MW plant. Of the material leaving the sinter furnace, one half must be recovered in a suitable size range and returned to the collector to serve as fresh collection sites.

Assuming that fuel oil additive is utilized at a rate of 2% by weight of the collected ash to promote sticking, a total of 920 lbs/hr of oil must be utilized as additive with a Btu content of 18,700 Btu/lb, containing a total heat value of 17,204,000 Btu/hr. This represents 0.313% of the boiler heat input rate of 5.5 x 10^9 Btu/hr. The additive oil contains sufficient heating value to raise the ash coated aggregate 625°F in temperature upon introduction to the sintering volume, assuming an aggregate specific heat of .3 Btu/lb.°R. Additional heat value would be available from the carbon content of the ash sample. Although air must be utilized to combust the oil, heat departed to the required combustion air can be recovered in sintering is performed in the boiler. Assuming that through heat recovery combustion air is exhausted at a temperature 200°F higher than at the air intake, just 3% of the oil heat value is lost to the required combustion air (this is calculated from an air specific heat of .241 Btu/lb.°R, an air oxygen content of 23% by weight and assuming that 100% of the oil goes to CO_2). This small fraction can be ignored, but would be significant if heat recovery was not utilized. Additional fuel must be utilized to raise the ash coated aggregate to 1900°F. Assuming that asn coated aggregate is maintained at the 300°F at which it is withdrawn from the electrofluidized bed, then it must be raised a total of 1600°F in temperature to reach the required 1900°F. This requires a total heat value of 44,032,000 Btu/hr, of which 39% is already contained in the collection additive. After ash is withdrawn from the sintering volume only indirect heat recovery can be utilized because of the difficulties involved in moving a solid through a pressurized gas stream (rotary valves are generally not suitable for solids larger than 200 mesh). Assuming that the heat content of sintered material is lost, a total heat loss to the boiler of 2.68×10^7 Btu/hr is incurred in addition to the heat value of the additive. This heat loss represent 0.49% of the boiler heat input rate. Table 4.1 summarizes these results.

TABLE 4.1

Heat Required for Ash Sintering as Percentage of Boiler Heat Input

Additive heat value as percentage of boiler heat input	0.31%
Heat required for sintering as percentage of boiler heat input	0.80%
Net boiler heat loss for sintering	0.49%

This rate of heat utilization must not be out of line with a level which would be acceptable to utilities, since slagging boilers which utilize flyash reinjection lose approximately half this much heat to slag.

The two-stage electrofluidized bed collector illustrated in Fig. 4.8 incorporates 2,292 ft^2 of bed area per stage on each side of the stack. The system measures 52' x 52' overall, with four feet of the overall length allowed for insulation and dividers between the 8' x 8' distributor plates. Each module processes 745,000 acfm of the flue gas which results in a bed superficial velocity of 325 fpm. Particle feed is accomplished by a bucket elevator to two centrally located points above the upper bed. Particles are metered from the upper bed to the lower bed by vibrating feeder, and subsequently by vibrating feeder from the lower bed to reprocessing. Due to the 52' width of the system it seems desirable to run a conveyor belt (or screw conveyor) to bring particles from the various beds to the edge of the collector rather than raise the collector. The conveyor belt running under the system could be led directly to the reprocessing system. The plan view shows a location where dampers could be positioned to divide the collector into three sections and accomodate unit turndown. Rick Zimbone reports that the Mystic 7 unit runs at approximately 580 MW during the day and 150 MW at night. Additive injection would be required for both the upper and lower stage, and would typically be injected from above the distributor plate. The two stage collector would require a system pressure drop of approximately 8" to 13" of water .

b. Electrified Bed

Figure 4.9 illustrates the application of a one-stage Electrified Bed to the Mystic 7 application. To facilitate effective charging the one-stage collector is preceded by a multiclone. Two-stage collection can also be utilized, and is discussed later in this section in relation to dry SO_2 collection (see Fig. 4.10). The one-stage collector as shown is designed to treat a total of 745,000 acfm of flue gas, providing 19,905 ft^2 of collection area and a superficial velocity of 74.8 fpm. This low superficial velocity should provide a system pressure drop of below 3" WG, with the multiclone adding approximately 3" WG to the collector pressure requirements.

The collector as shown can employ the fluidized bed cleaner developed by EFB, Inc. (see Fig. 3.14). Collection additive is not required because

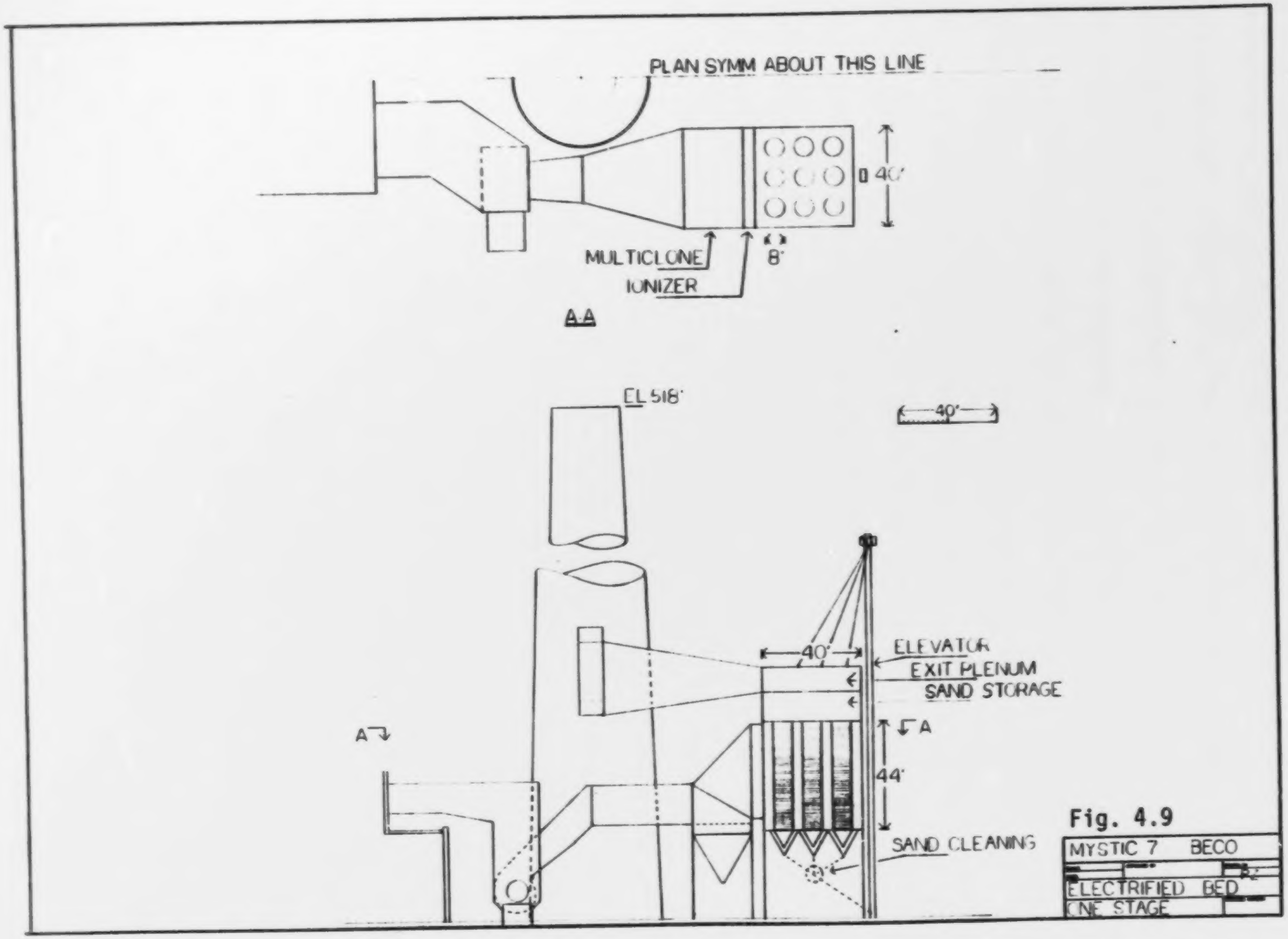

PLAN SYMM ABOUT THIS LINE
40'
8'
MULTICLONE
IONIZER
A-A
EL 518'
40'
40'
ELEVATOR
EXIT PLENUM
SAND STORAGE
A
A
44'
SAND CLEANING
MYSTIC 7 BECO
ELECTRIFIED BED
ONE STAGE

Fig. 4.9

of the low level of particle agitation in the collector. An ionizer such as the high intensity ionizer could operate effectively in the space provided between the multiclone and the collector inlet. The collector should provide an efficiency well in excess of that required to achieve the NSPS particulate standard (see Chapt. 3). System pressure drop scales linearly with flowrate and collection efficiency increases for lower flowrates.

c. Electrified Bed, Spray Dryer

Figure 4.10 illustrates the application of a two-stage Electrified Bed collector downstream from a spray dryer SO_2 collection system. Dry SO_2 collection is inherently attractive since the problems of severe material corrosion and saturated plume are not encountered. The spray dryer technology allows calcium based reagents to be utilized by injecting them into the gas stream in a fine slurry form. As the water is evaporating away from the suspended reagent particles, SO_2 is collected. To avoid corrosion problems injected water should be evaporated before the gas reaches downstream collection equipment. Systems are presently under construction to use both baghouses and electrostatic precipitators as the downstream collection device, since reaction can continue as gas passes through the bag cake. Reaction on the bag cake is somewhat in contradiction to the concept of drying the reagent before it reaches the baghouse, but this effect is plainly reported in the scant literature [2,3,4,5]. The two-stage Electrified Bed as shown in Fig. 4.10 provides a maximum of gas to collected solids contacting for large solids.

Large solids, including almost all of the ground reagent, are collected in the first stage of the two-stage Electrified Bed. For the application of the spray dryer, the first stage is shown as being the upper stage to

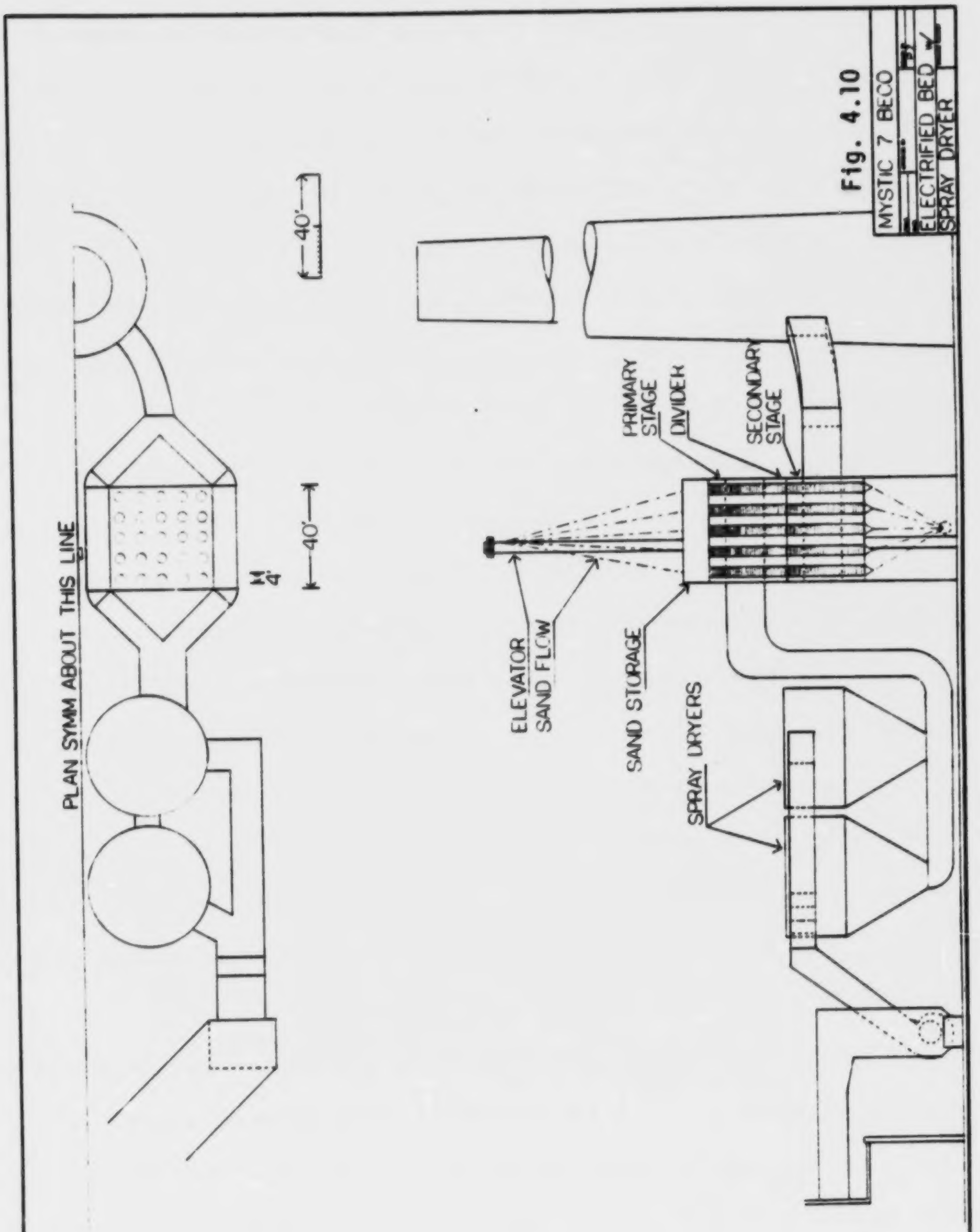
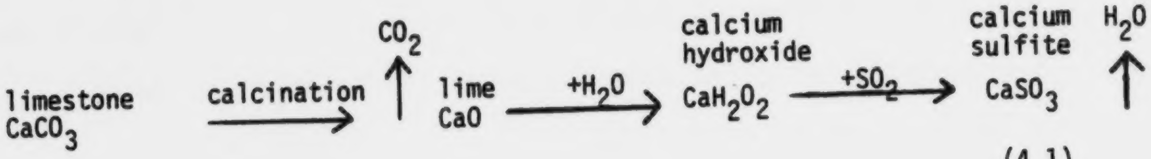


Fig. 4.10
MYSTIC 7 BECO
ELECTRIFIED BED
SPRAY DRYER
PLAN SYMM ABOUT THIS LINE
4'
40'
40'
ELEVATOR
SAND FLOW
SAND STORAGE
SPRAY DRYERS
PRIMARY STAGE
DIVIDER
SECONDARY STAGE

maximize gas contacting time for the reagent. Fine particles passing through the first stage are charged as they pass down through the center of the cylinders and collected with high efficiency in the lower bed. With this configuration solids spend a minimum of half of the total bed rotation time in contact with the flue gas. Tests performed by EFB, Inc. have shown that particle beds can increase their weight with collected ash by as much as 10%. Using a 2.39 gr/aft^3 ash grain loading for Middletown 3 design coal as calculated in Appendix B (assuming a worst case 14% boiler ash retention), a bed rotation period for the collector can be calculated.

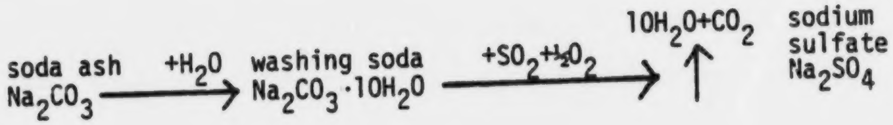
The two-stage collector illustrated in Fig. 4.10 provides 9,430 ft^2 of collector facial area on each side of the stack. When treating the full load 745,000 acfm, a collector facial velocity of 79 fpm results. In each module 25 4' diameter collector tubes provide 30' of vertical collection area in both the upper and lower stage, with a charging wire contained in the center of each tube. Using a collector bed depth of 5", a stone density of 100 lb/ft^3, and a gas grain loading of 2.39 gr/aft^3, a bed 10% ash loading results after 154 minutes. Consequently, solids collected in the first stage under these conditions would spend between 77 minutes and 154 minutes in contact with the flue gas stream. Bed rotation speed would have to be increased to account for the increased weight of reagent.

The weight of reagent required to perform SO_2 collection can be calculated assuming a 1 to 1 stoichiometric ratio between reagent and SO_2 [16]. Two reagents, calcium hydroxide and sodium carbonate are generally employed for SO_2 collection in spray dryers [3]. Calcium hydroxide can be produced through the calcination and subsequent slaking of limestone. Sodium based reagents are generally more reactive, more expensive, and more difficult to dispose of. Sodium bicarbonate, not proposed for use with the spray dryer technology, reacts significantly with SO_2 in the dry state [2]. Sodium carbonate, known commonly as soda ash, will readily absorb water in the spray dryer and convert to sodium carbonate decahydrate, commonly known as washing soda. After reaction with SO_2 sodium sulfate results. The chemical reactions described are shown below in Eqns. 4.1 and 4.2.



$$\overset{\text{limestone}}{CaCO_3} \xrightarrow{\text{calcination}} CO_2\uparrow \; \overset{\text{lime}}{CaO} \xrightarrow{+H_2O} \overset{\text{calcium hydroxide}}{CaH_2O_2} \xrightarrow{+SO_2} \overset{\text{calcium sulfite}}{CaSO_3} \; H_2O\uparrow$$

(4.1)



$$\overset{\text{soda ash}}{Na_2CO_3} \xrightarrow{+H_2O} \overset{\text{washing soda}}{Na_2CO_3\cdot 10H_2O} \xrightarrow{+SO_2+\frac{1}{2}O_2} 10H_2O+CO_2\uparrow \; \overset{\text{sodium sulfate}}{Na_2SO_4}$$

(4.2)

The sodium sulfate resulting from Eqn. 4.2 is highly water soluble and reportedly damaging to the quality of ground water, while calcium sulfite is relatively insoluble [2]. Although other reactions will certainly participate in the spray dryer SO_2 collection process, these two mechanisms allow us to estimate the solids requirements for collection. It has already been mentioned in the previous section that 12,000 Btu, 1.8%S coal represents the highest sulfur coal for which dry collection remains economic. Following the analysis contained in Appendix B, for this coal a flue gas sulfur grain loading of .65 gr/aft^3 would result. For the process described in Eqn. 4.1, the ratio of calcium sulfite weight to sulfur weight is 3.75, and a salt grain loading of 2.44 gr/aft^3 results. For the process described in Eqn.

4.2 the ratio of sodium sulfate weigth to sulfur weight is 4.44, and a salt grain loading of 2.89 gr/aft^3 results. Consequently, for both SO_2 reaction processes the total gas solids loading must double from that experienced with fly ash alone (this estimate has been derived through the use of the many assumptions listed, and the actual ratio will vary). For the collector configuration shown in Fig. 4.10 a bed rotation time of 77 minutes will result, and solids will spend between 38.5 minutes and 77 minutes in contact with the flue gas stream. This time is significantly longer than that available in an ESP, and generally longer than can be achieved in a baghouse. Consequently, good solids utilization should result.

The two-stage Electrified Bed as reported in Chapt. 3 should provide an efficiency sufficient for achieving the particulate NSPS standard. Solids can be delivered throughout the sand storage area through the use of a bucket elevator with a distribution box operating in overflow mode at the discharge. Material is metered from each of the 25 tubes by vibratory feeders feeding to a central conveyor, which in turn carries the material to the fluidized bed reprocessor and back to the elevator. The central conveyor can be eliminated if the collector is built sufficiently high above ground level. The elevator is located in a position where it could service both collection modules. Ducting is split both at the inlet and the outlet of the collector to bring tube interstitial velocities to a low value and help insure even flow distribution.

The two spray dryers shown were sized from the available literature. A configuration preferred by Stork Bowen Engineering is to provide three centrifugal atomizers in each spray dryer chamber. Each atomizer is equipped with a 150 hp electric motor. This motor size and capacity is consistent with atomizers already in use by spray dryers in other industries [3]. Gas after entering the upper plenum of the spray dryer is split into three streams which pass axially along each of the atomizer shafts, and consequently perpendicular to the slurry discharge. A damper should be provided before each dryer module to facilitate turndown and maintenance.

d. Charged Droplet Scrubber

Figure 4.11 illustrates the application of the charged droplet scrubber to the Mystic 7 application. Tests by Pilat reported in Chapt. 3G (Table 3.19) show that efficiencies on coal emissions ranging from between 99.77% and 99.89% can be achieved by one-stage operation of the CDS collector. For the two case study coals reported in Appendix A, to achieve the NSPS particulate standard efficiencies of 99.39% and 99.79% are required. Since the higher efficiency is required for coal with an ash content higher than that generally observed in New England, it can be concluded that oepration of just one stage of the CDS collector is sufficient for achieving the NSPS standard.

The EPA has sponsored tests of the University of Washington charged droplet scurbber for combined particulate and SO_2 collection. A paper reporting the results of these tests is scheduled for delivery at the "Second Symposium on the Transfer and Utilization of Particulate Control Technology" sponsored by EPA and scheduled to be held at the end of July, 1979 in Denver. Results from these tests were not available as of this writing. Pilat reports by telephone that the system described in Chapt. 3G was utilized for the combined collection tests, with the addition of a scrubber liquid recycle system. Good tests have so far been obtained, but the system has not yet been tested with relatively insoluble reagents such as calcium hydroxide which require the handling of suspended solids. Pilat reports that SO_2 collection efficiency rates were consistently enhanced by the charging of spray droplets, despite the reduction in droplet density caused by self precipitation.

Although is would seem apparent that the enhanced collection efficiency of charged droplets is due to their greater velocities (electrically driven)

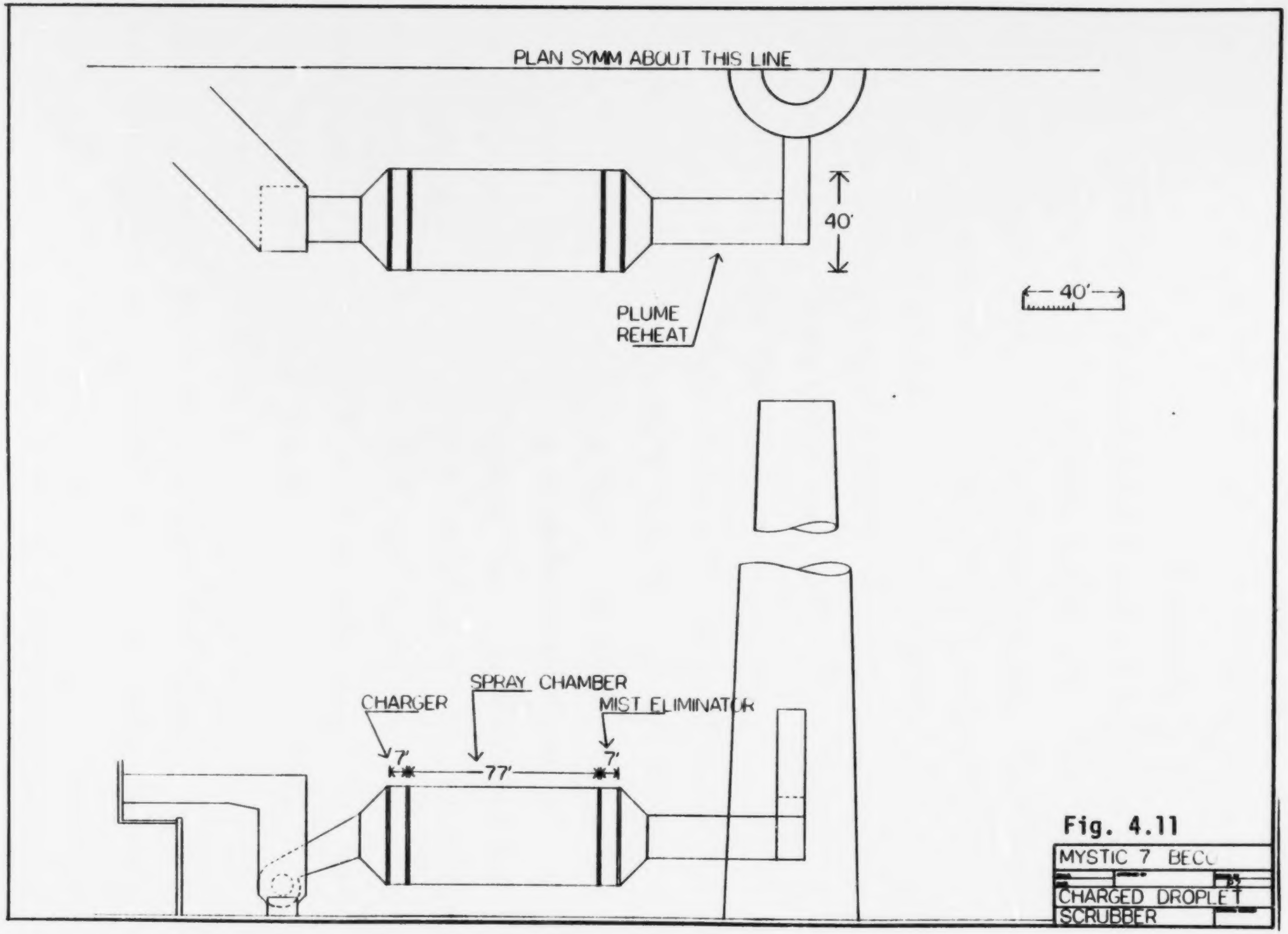

PLAN SYMM ABOUT THIS LINE
40'
40'
PLUME REHEAT
CHARGER
SPRAY CHAMBER
MIST ELIMINATOR
7'
77'
7'

Fig. 4.11

MYSTIC 7 BECO

CHARGED DROPLET
SCRUBBER

and consequent greater transfer rates, this conclusion is not supported by the high mass transfer potentials of gas phase collectors. The order of magnitude of a spray system's transfer potential can be found by using the 3×10^8 drops/m^3 density reported in Chapt. 3G as a characteristic length and the 3 sec residence time typical of wet SO_2 collectors. These numbers can be combined with the SO_2 diffusion coefficient of .164 cm^2/sec to yield a parameter proportional to the mass transfer capability. This ratio is reported in Eqn. 4.3.

$$\frac{D\,\tau_{res}}{\ell^2} = \frac{.164\ \frac{cm^2}{sec}\ 3\ sec}{(.022\ cm)^2} \approx 10^3 \qquad (4.3)$$

Without taking account of the relative motion between droplets and gas, a high transfer capability is reported. The Sherwood number is proportional to the enhancement of mass transfer caused by convection. The Sherwood number for a droplet in motion normalized to the Sherwood number of a stationary droplet is reported in Eqn. 4.4.

$$\frac{SH}{SH_o} = 1 + 0.3\ \left(\frac{\mu}{\rho D}\right)^{1/3} \sqrt{\frac{d_p U_p}{\mu}} \qquad (4.4)$$

This enhancement will typically be substantial, so it can be concluded that equilibrium between gas and liquid in a wet scrubber is quickly established, and scrubber size is determined by factors other than mass transfer between liquid and gas. In addition, the diffusion of SO_2 into the surface of water is reported to be practically instantaneous. Pilat has declined to speculate on the cause of the efficiency enhancement.

During one-stage operation Table 3.19 reports gas residence time in the gas charging region of approximately 0.8 sec., residence time in the spray tower region of 9 sec., and residence time in the mist eliminator sectio of 0.8 sec. The configuration shown in Fig. 4.11 provides these residence times in a 38' by 38' horizontal volume, with one additional foot provided on each side and between stages for structure and insulation. The University of Washington scrubber as well as the Weir scrubber utilized in FGD control consists of relatively open horizontal chambers. The majority of wet SO_2 scrubbers are arranged in a vertical fashion with gas passing up counterflow to water flow [8,17]. Horizontal scrubbers operate at flow velocities of greater than 1200 fpm, while vertical scrubbers generally operate at flow velocities of less than 500 fpm [18]. Pilat operates his scrubber at 142 fpm in its present configuration for particulates control, but it seems likely that this value would and could be increased because of the difficulties which would result in flow distribution for a large system. The collector depicted in Fig. 4.11 treats 745,000 acfm of flue gas, (which will contract to 610,000 acfm when saturated with water, increasing the residence time of later stages) and provides a superficial velocity starting at 516 fpm and decreasing to 422 fpm.

Stack reheat must be utilized for this configuration to provide plume buoyancy. To achieve the 70% emission reduction required for a new source burning low sulfur coal it is possible that some stack gas could be bypassed from a wet collector and used to reheat the plume, but this is not convenient here since the scrubber is also employed for particulates collection. It is reported that for some powerplants in Japan a separate oil or gas burner is utilized to reheat the plume, and this burner consumes as much as 5% of the plant's requirements [19]. Finned heat exchangers powered by steam from the boiler are more commonly utilized in the United States, but these have been the source of many operating problems. It is generally considered undesirable to place equipment in the flue gas stream between a wet scrubber and the reheat section because of the severe corrosion problems resulting from acid mist.

Since electric fields are utilized for particulates collection in this scrubber, collection efficiency for both particulates and SO_2 should increase as the unit is turned down and flow velocities are decreased. Figure 4.11 does not depict the significant volume which must be utilized by pumps and other support equipment to perform wet SO_2 scrubbing. For double alkali processes the volume of support systems can be greater than that of the collector itself [8].

e. Electrostatically Enhanced Bag Filter

Figure 3.24 illustrates the present configuration of the Apitron electrostatically enhanced bag filter. The illustrated module is used for all application flowrates at this time, with the necessary collection area provided by placing modules one next to the other. Each module will contribute 7'5" to the overall width. The 7'5" modules contain 72 bags and 72 charging elements, with a resulting bag surface area of 1,800 ft^2. At the nominal bag facial velocity of 8.25 fpm, the module depicted in Fig. 3.24 exhibits a flue gas treatment capacity of 14, 850 acfm. Consequently, a plant such as Mystic 7 would require two collectors of 50 modules each in order to treat the full load flue gas volume of 1.49×10^6 acfm. If 50 of the modules depicted in Fig. 3.24 are lined up end to end a total colelctor length of 371' will result, with a height of 34' and a width of 12' as illustrated.

For a large utility application the total length of the collector could be reduced through the utilization of longer bags, the stacking of collectors, or by increasing the baghouse width. Figure 3.23 illustrates the application of a conventional reverse air baghouse to the coal fired Kramer Station utility plant. Note that the individual bag filter houses are roughly square, minimizing the system material requirements, heat loss, and ducting requirements. This type of design philosophy would in all probability be applied to the Apitron concept if the firm was awarded a utility contract. The present marketing effort for the Apitron system is primarily directed toward smaller industrial applications, since the technology is in its infancy. Consequently for the purpose of comparison it seems appropriate to compare the residence time of the filter exclusive of hopper volume to the residence times of other collectors. Note that the baghosue illustrated in Fig. 3.23 is suspended well above the ground and railroad tracks have been run beneath, apparently to remove collected ash. Ash hopper volume and system height above the ground will depend on the number of points from which ash is removed (hopper volume and system height can be reduced if ash is removed from a greater number of points and/or with greater frequency), ash removal frequency, and system dimensions. Consequently the bottom hopper volume should be excluded from measures which attempt to characterize the size of a particular technology.

The 50 module collector which is required for treating one-half of the Mystic 7 emissions has an active length (volume of precipitator and baghouse sections only, excluding the bottom hopper) of 371', an active width of 11'10", and an active height of 21'5" (see Fig. 3.24). These dimensions multiply out to a total collector volume of 94,023 ft^3, and when treating 745,000 acfm an active residence time of 7.57 sec results. This value is extremely close to the 7.65 sec active residence time of the present ESP at Mystic 7, and consequently Fig. 4.7 provides a visual reference by which the size of the required Apitron collector can be judged. Both the electrostatic precipitator and the Apitron collector require a long surface area across which the entering and exiting gas flow must be distributed.

In order to achieve SO_2 collection spray dryers such as those illustrated in Fig. 4.10 could conceptually be placed in front of the Apitron collector. A problem area for the coupling of these two technologies is the rapid cleaning cycle employed for the Apitron bags, typically 40 sec. This rapid cleaning cycle could reduce the efficiency of utilization for reagent. As was discussed in Chap. III, rapidity of cleaning cycle and smaller collector size characterizes the Apitron filter as well as conventional pulse-jet baghouses in comparison with the reverse air/shaker types generally employed by utilities.

D. Brayton Point 2, New England Electric

1. Preliminary Evaluation of Innovative Technologies for Plant Requirements

Figure 4.12 illustrates the present configuration of the 187 SCA ESP on Brayton Point 2. As discussed in Sec. II4, New England Electric plans to add new precipitator volume in series with the present collector to satisfy the provisions of the coal conversion plan worked out in cooperation with state and federal environmental authorities. Although the efficiency deficit which must be overcome in order to achieve the .08 lb/MMBtu standard when burning design coal is only marginal, present plans call for the present SCA to be almost tripled according to Mr. Molino of New England Electric. Mr. Molino suggests that this significant increase in collection area is warranted to assure compliance if a batch of extremely low sulfur or high ash coal is fed to the boiler. Consequently, the goal of innovative technologies should be to enhance the efficiency of the present collector to an extent equivalent to that of doubling the present volume. Doubling the present SCA would boost the total SCA to 374 ft^2/1000 cfm, and with a nine inch duct width this is equivalent to a total influence time of 8.4 sec. Substituting a nominal value for ESP electric field of 3.06×10^5 V/m, a viscosity of 2×10^{-5} kg/m·sec, and the 8.85×10^{-12} f/m air dielectric constant, an ESP parameter as described in Appendix A of 3.05 (1/μm) is found to describe the enlarged ESP. This size ESP is in excess of that required to meet the benchmark and NSPS standard for case study A coal, and is slightly shy of that required to achieve these stnadards for case study B coal. Since case study B coal as described in Appendix A has a higher ash content than coals which are likely to be employed by New England Utilities in the future (despite the gradual future reduction

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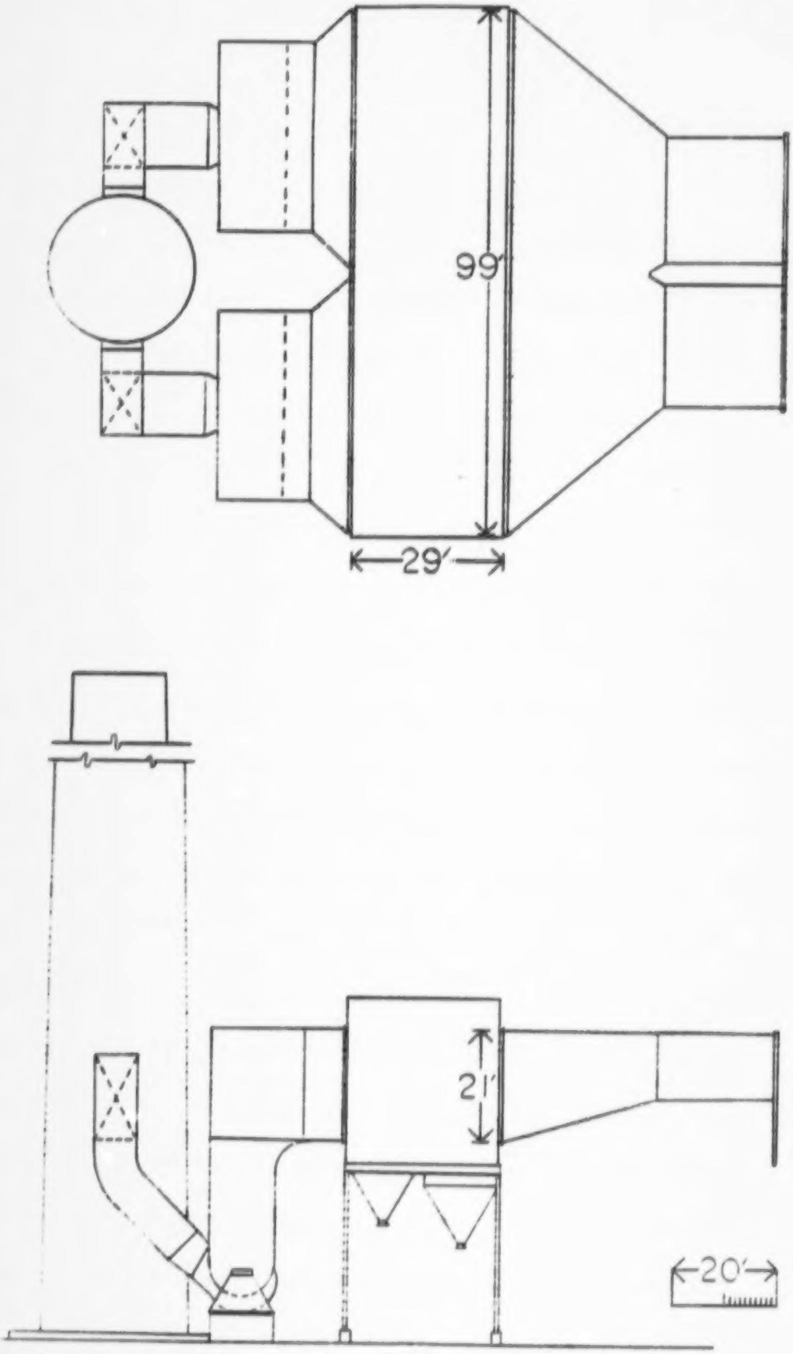


Fig. 4.12 Brayton Point 2, New England Electric, as is with electrostatic precipitator.

of steam coal quality), the doubling of the present ESP volume should be considered sufficient for achieving the benchmark fine particle standard.

Electrofluidized Bed

Examination of the theory which describes the efficiency of the electrofluidized and Electrified Bed reveals that an efficiency parameter, equivalent to that described in Appendix A for an ESP, can be derived and is shown as Eqn. 4.5

$$\frac{3\pi}{4}\frac{\ell_o}{U}\frac{E^2\varepsilon_o}{D\,\mu} \tag{4.5}$$

ℓ_o ≡ bed depth

U ≡ bed superficial velocity

D ≡ aggregate diameter

Using the efficiency parameter in Eqn. 4.5 a required bed depth can be found which will effectively double the volume of the present ESP when placed in series as a retrofit. By substituting a nominal value of 4×10^5 V/m for electric field, an aggregate diameter of 4×10^{-3} m, and a superficial velocity of 325 fpm for the electrofluidized bed and 80 fpm for the Electrified Bed, it can be found that an electrofluidized bed depth of 6.05 cm and an Electrified Bed depth of 1.50 cm is sufficient to provide the desired enhancement of system efficiency. In the case of the electrofluidized bed a somewhat deeper bed will be required to account for the effect of bubble bypass, although this depth can be adjusted at will to provide the optimum tradeoff between efficiency and pressure drop. In the case of the Electrified Bed a minimum bed depth of 3" is employed, and consequently a wide margin in efficiency is provided.

In the case of Brayton Point 2 a sufficient space is available for employment of both the electrofluidized bed agglomerator and electrofluidized bed collector. The 309 fpm superficial velocity of the Brayton Point 2 precipitator is on the same order as the 325 fpm superficial velocity of the electrofluidized bed, a feature which reduces the complexity of retrofit. Although no excess fan power is presently available for Brayton Point units 1 and 2, Mr. Molino of New England Electric is optimistic that the present ID fans can be upgraded to provide as much as 3" WG additional pressure to accomodate the additional ESP volume and ductwork. Since the electrofluidized bed will require a pressure drop on the order of 8" WG, utilization of this technology would require that the present ID fans be modified or replaced. The employment of both the electrofluidized bed collector and agglomerator is discussed in Sec. 2.

Electrified Bed

The Electrified Bed collector, as already discussed, will provide an efficiency more than adequate to meet the retrofit requirements of the Brayton Point facility. As shown in Sec. 2, the Electrified Bed one-stage collector can be installed in the area presently employed to change the direction of gas flow from the exit of the ESP to the fan inlet. Since the one-stage Electrified Bed requires 3" WG of pressure drop, an upgrading of the present ID fans should provide sufficient static pressure drop to power the retrofit collector.

High Intensity Ionizer

The high intensity ionizer can be readily installed in the inlet plenum of the Brayton Point 2 ESP due to the low design superficial velocity and the relatively shallow angle employed for the present ESP inlet plenum. As depicted in Sec. 2, sufficient space for the high intensity ionizer can be provided before the inlet of the present ESP simply by sharpening up the angle of the inlet plenum to a reasonable 45°. In addition, the minimal 1/4" WG pressure drop required by the HII could with great probability be supplied by the present fans.

Although the installation of the HII at Brayton Point 2 appears to be feasible, there is much uncertainty as to whether the HII would provide the performance enhancement desired by New England Electric. As described in Chapter III, the enhancement claimed by promoters of the HII is precisely that desired by New England Electric, an effective doubling of the present ESP volume. Data is provided which documents this enhancement for a 100 SCA laboratory ESP which is smaller than the 187 SCA collector presently in use. Collection theory as reviewed in Chapter III suggests that the degree of enhancement should be reduced as precipitator SCA increases and as coal sulfur content decreases. While present plans call for moderate 1.5%S content coal to be burned at Brayton Point, Mr. Molino was specifically concerned about the collection efficiency at times when batches of low sulfur coal are fed to the boiler. Since the plans of New England Electric to double the present ESP volume should provide a wide margin for compliance, it seems likely that compliance could be achieved by the HII in most cases. Consequently the technology is appropriate for consideration to meet the requirements of Brayton Point 2 with respect to compliance with the coal conversion plan.

It has already been found in this section that the present ESP at Brayton Point 2 displays an ESP parameter as described in Appendix A of 1.525. Consequently, to achieve the benchmark fine particle standard and new source performance standard for case study A coal a 44% enhancement in effective collection volume must be achieved. This enhancement could potentially be provided by the HII. The 239% enhancement required to achieve these standards for case study B coal is apparently beyond the capability of the HII.

Wet Electrostatic Precipitator

Charged Droplet Scrubber

Wet technologies are generally not attractive unless flue gas desulfurization is planned due to both corrosion problems and the requirement for stack gas reheat. Since Brayton Point 2 has entered into an agreement with state and federal environmental authorities to convert to coal without employing FGD, the two wet technologies of this study are not considered as likely alternative approaches for solving the particulate control problem.

Electrostatically Enhanced Bag Filter

The electrostatically enhanced bag filter (EEBF) is a large collector which is better suited for new installations and replacements than for retrofits. Consequently the EEBF is not considered for the Brayton Point application in which limited space is available and a functional ESP is presently in place.

2. Equipment Layout for Selected Innovative Technologies

a. Electrofluidized Bed Agglomerator

Figure 4.13 illustrates the application of the electrofluidized bed agglomerator to the Brayton Point 2 facility. The agglomerator has been divided into six vertical bed sections which span the entire width of the ESP. This large number of beds was required in order to reduce the space requirement of the collector in the direction fo flow. Simply by sharpening up the angle of the ESP inlet plume to 45° it is possible to create sufficient space for installation of the agglomerator.

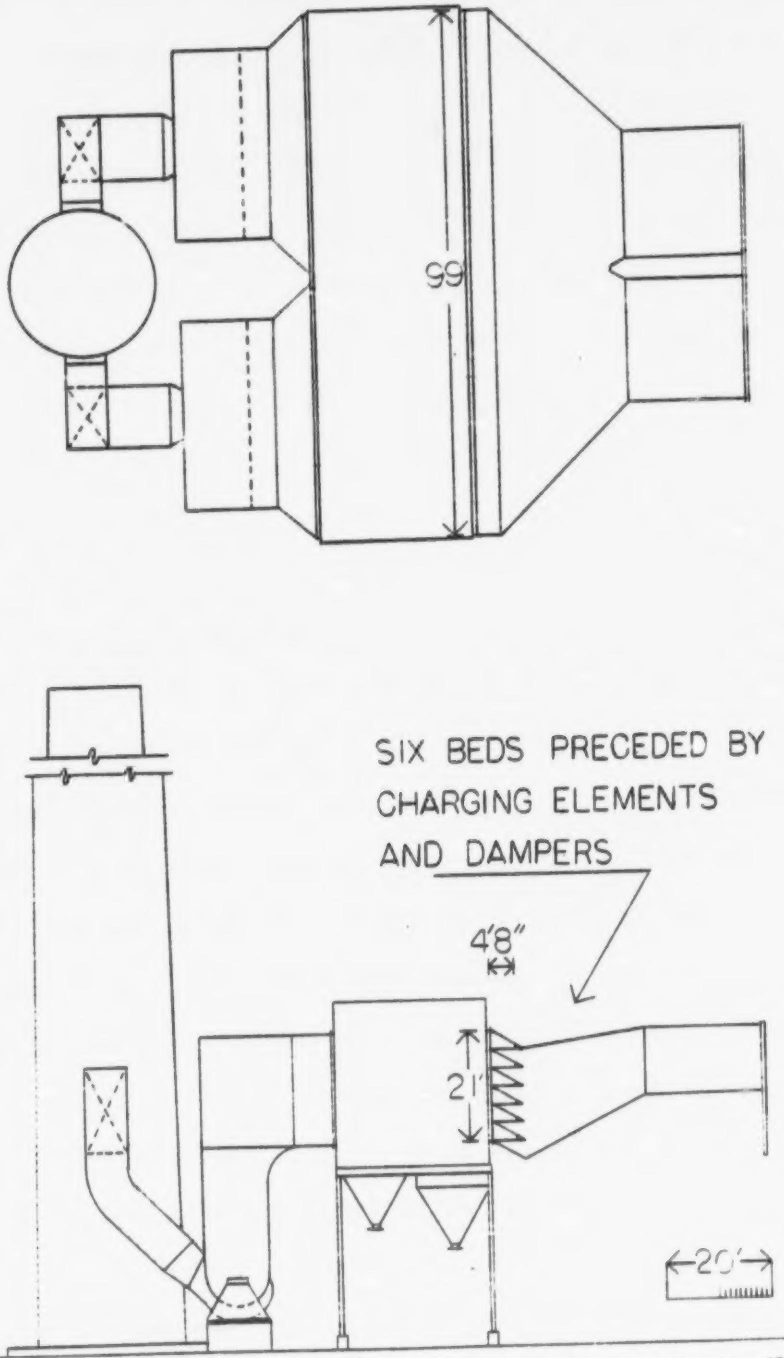

99
SIX BEDS PRECEDED BY
CHARGING ELEMENTS
AND DAMPERS
4'8"
21'
20'

Fig. 4.13 Brayton Point 2, New England Electric, electrofluidized bed agglomerator retrofit.

The agglomerator does not require material handling or regeneration equipment in order to operate, since removal of material from the gas stream is effected by the present precipitator equipment. The agglomerator serves the function of agglomerating fine particles into large ones which can be more readily collected by the ESP. In order to operate the agglomerator both additive injection equipment and charging apparatus must be employed. Present plans call for additive to be sprayed into the top of fluidized beds, with the action of the fluidization serving to evenly spread the material throughout the bed. Additive injection equipment design cannot be executed until more development has occurred with respect to potential additive materials. Additive must serve to hold ash together without strongly sticking ash to the surface of the ESP plates.

In addition to additive injection equipment both charging elements and dampers must be employed in the gas stream before the electrofluidized bed agglomerator. Ionizing elements will be placed directly below the six distributor plates to maximize their effectivenes. Dampers must be employed to keep the flowrate through each bed above the minimum fluidization velocity and below the point where spouting occurs in the bed. Spouting would tend to significantly lower the collection efficiency of the system, while a bed below minimum fluidization velocity will tend to build up with ash since it has lost its cleaning mechanism. An alternative mode of operation to using dampers would be to allow several of the beds to completely blind with ash and serve to raise the flow velocity in other beds during turndown operation. This mode has not been tested.

The six beds extend the entire 99' width of the collector, and each bed has an active width of 4'8". With a design facial velocity of 325 fpm

26% of the total bed area is allowed for structural support, bed isolation, and insulation on the ends. The 99' length should be divided up into sections to insure that areas do not become completely devoid of particles.

b. Electrofluidized Bed Collector

Figure 4.14 illustrates the application of the electrofluidized bed collector to the Brayton Point 2 facility. As in the case of the agglomerator, six beds are employed with modules on both sides of the stack. After leaving the collector, gas is looped back to the stack through the same breeching as is presently employed by the ESP. Two elevators are employed for each collection module to reduce the horizontal distance which particles must travel to enter the reprocessing loop.

A suitable additive has not yet been identified for collector operation. Consequently it is difficult to design the reprocessing and additive injection systems pending further development. Similar to the requirements of the agglomerator both ionizer and dampers must be employed ahead of the distributor plates of the electrofluidized beds. Although particles may be charged after they leave the electrostatic precipitator, this charge cannot be relied on for collection due to the fan and ducting which lie between the two collectors. To achieve the design facial velocity of 325 fpm the electrofluidized bed collector must provide 2,203 ft^2 of distributor plate area to accomodate the full-load gas flow of 716,000 acfm. The collector as shown provides a 26% excess margin in area to allow for structural support, insulation, feeders, and bed divisions.

Dampers are required to maintain the various sections of the collector at fluidization velocity when the unit is turned down. Unlike a panel bed in which gravity alone provides the force necessary to rotate bed material,

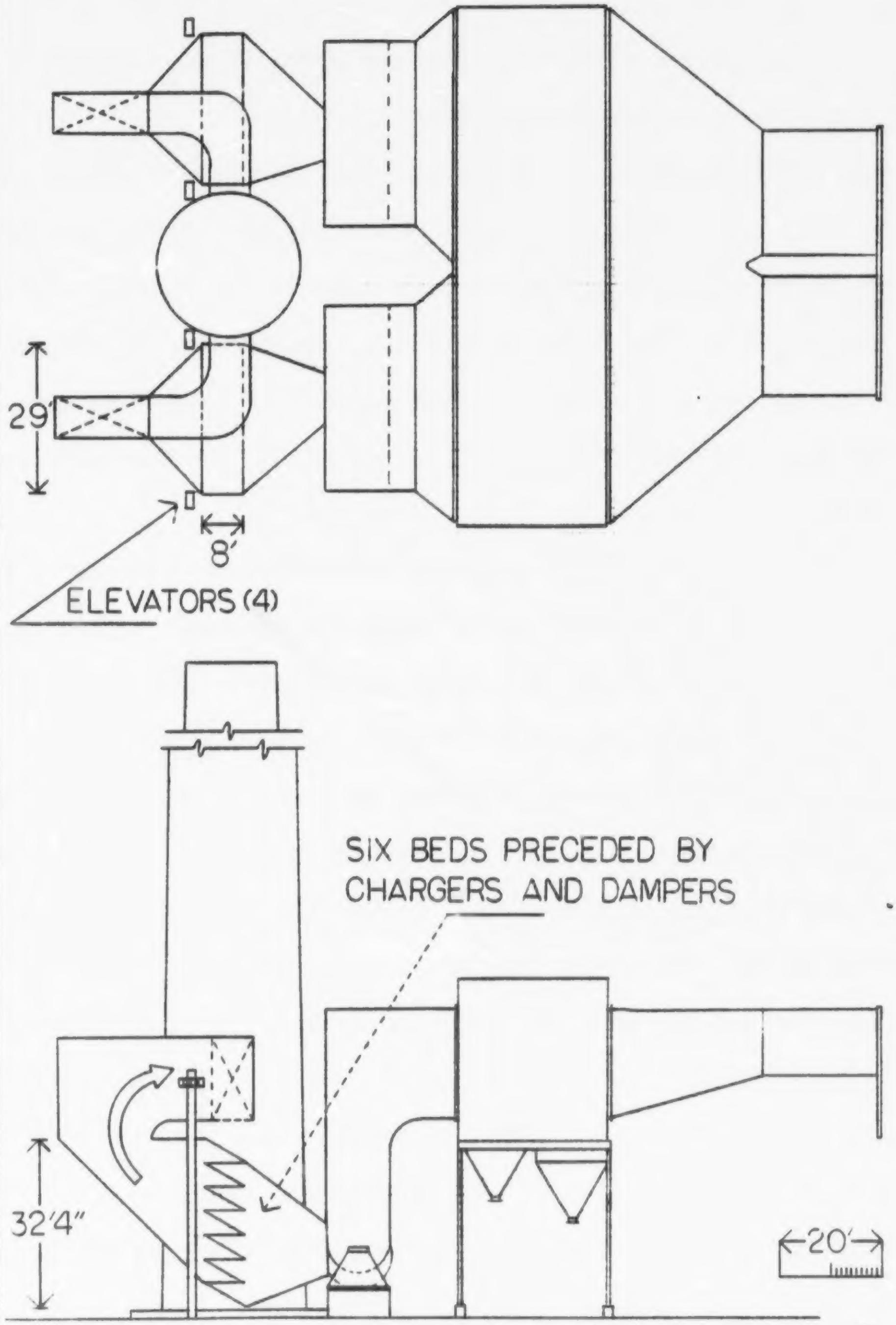

29'
8'
ELEVATORS (4)
SIX BEDS PRECEDED BY
CHARGERS AND DAMPERS
32'4"
20'

Fig. 4.14 Brayton Point 2, New England Electric, electrofluidized bed collector retrofit.

in fluidized beds sufficient air must be provided to move particles laterally across the bed to a discharge point. It is possible that if a collector bed section is operated below the minimum fluidization velocity that it will eventually blind with ash and enhance the flow in other regions which can then operate normally. This mode of operation has not yet been tested.

c. Electrified Bed

Figure 4.15 illustrates the application of the electrified bed to the Brayton Point 2 facility. The configuration depicted is a one-stage collector in which gas passes through the gravel bed filters from the outside to the center of the tubes, directly into the fan inlets. Gas exhausting from the center of a panel bed filter can pass either upward or downward with no increase in complexity. The ElB collector fits almost entirely into the flow region which is presently utilized to turn gas downward into the fan inlets. The collectors can serve to feed the fan inlets in a relatively uniform fashion. The collectors require 3" WG pressure drop which can reportedly be provided by an upgrading of the present fans.

Due to the location of the fans directly below the collectors as depicted in Fig. 4.15, gravity feed alone is not sufficient for transferring spent particles from the various tubes to the fluidized bed reprocessor (as shown in Fig. 3.14). Consequently a screw conveyor is shown in Fig. 4.15 to move particles horizontally away from the base of the tubes, and another conveyor is shown above the collectors to carry clean particles across to the tube inlets and reduce the height requirement of the bucket elevator. In Fig. 4.15 a total of two bucket elevators are employed, one for each collector module. Moderately sized 4 1/2' diameter tubes are employed to provide internal access. The collector size is proportional to the tube dia-

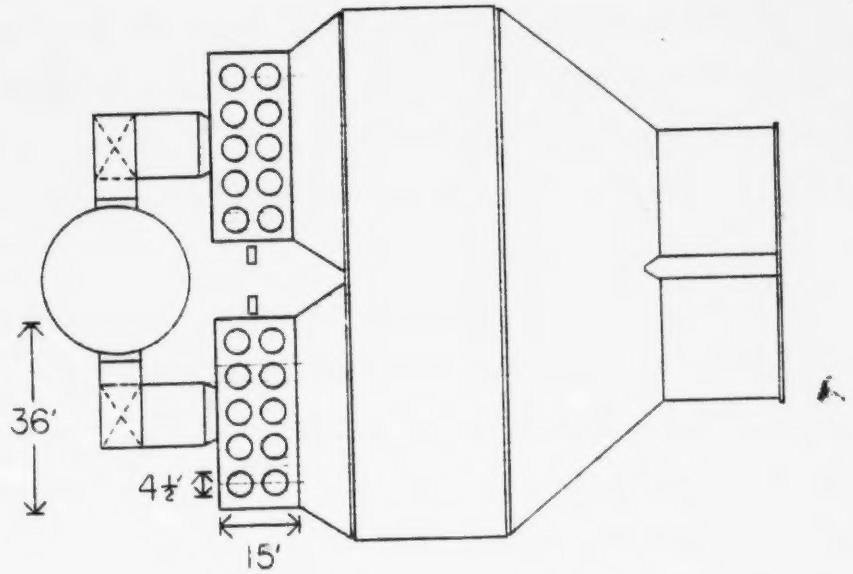
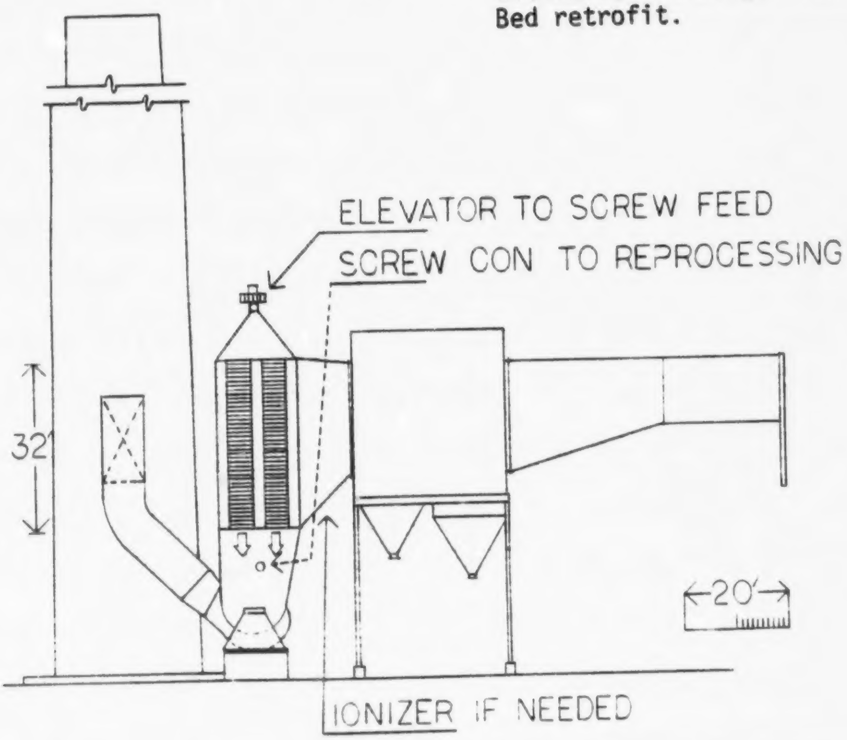


Fig. 4.15 Brayton Point 2, New England Electric, one-stage Electrified Bed retrofit.


ELEVATOR TO SCREW FEED
SCREW CON TO REPROCESSING
32'
20'
IONIZER IF NEEDED

meter for a given flow capacity, and tubes as small as 1' diameter have been employed.

The collector as shown provides a total facial collection area of 9048 ft^2, and a resulting facial flow velocity of 79 fpm at full load. As the unit is turned down collector pressure drop will decrease and efficiency will increase. The close spacing between the Electrified Bed and the ESP suggests that additional ionization of the particulate might not be required after it leaves the ESP. If additional charging is required, more than adequate space is available for installation of an ionizer such as the high intensity ionizer in the ductwork between the two collection systems.

d. High Intensity Ionizer

Figure 4.16 illustrates the application of the high intensity ionizer (HII) to the Brayton Point 2 facility. Adequate space in the direction of flow for installation of the HII can be provided by simply sharpening up the angle of the ESP inlet plenum to 45°. Union Carbide personnel report that HII installation required approximately 5' of space in the direction of gas flow.

The ionizer as shown covers an area of 99' by 21', and consequently would utilize 231 ionizer throats on 3' centers. Electrical shields would be required at the leading edge of the present ESP collection plates as described in Chapt. III, and some operational problems could occur in this application since there is no mechanical precollector before the HII. The effects of high ash loadings on the HII will be better understood as development work on the device progresses.

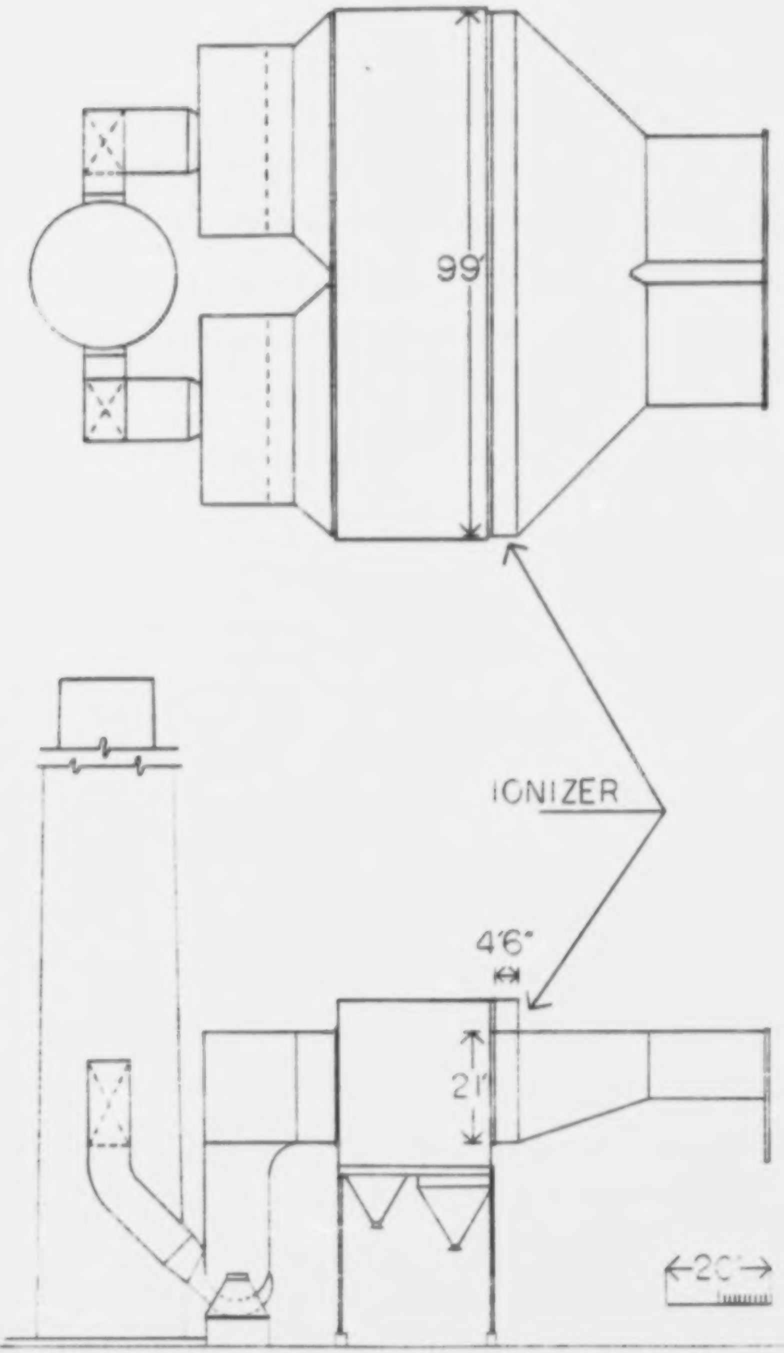

99'
IONIZER
4'6"
21'
20'

Fig. 4.16 Brayton Point 2, New England Electric, high intensity ionizer retrofit.

E. New Boston 2, Boston Edison

1. Preliminary Evaluation of Innovative Technologies for Plant Requirements

Figure 4.17 illustrates the present configuration of the ducting which stretches between the plant air heaters and smokestacks. New Boston 2 as well as New Boston 1 employs dual airheaters and stacks on approximately 40' centers. Consequently the equipment shown in the figures of this section must be employed twice for each unit. The flue gas passes horizontally through the air heaters immediately after which it turns vertically and breeches the roof. Figure 4.17 illustrates the ductwork between the roof breechings and the smokestack which are fixed atop the boiler support structure. As was previously discussed, New Boston 2 presently burns oil but was originally designed to be capable of pulverised coal combustion. Although space was allowed, plant equipment required for coal combustion was never purchased. Consequently, the plant would require coal handling and firing equipment as well as dust collection equipment to permit coal firing. A Stone & Webster plant drawing supplied by Boston Edison personnel shows a future electrostatic precipitator suspended with its base 42' above the turbine room roof. Since the support structure for this electrostatic precipitator is not yet in place, Boston Edison is not predisposed toward employing the illustrated collector in the event of coal firing. In addition, installing a precipitator of the required size to meet the state particulate emissions standard of 0.12 lb/MMBtu in the space allowed would be challenging. The question of particulate hardware choice is further complicated by the requirement for SO_2 collection.

Provisions of the Fuel Use Act have forced Boston Edison personnel

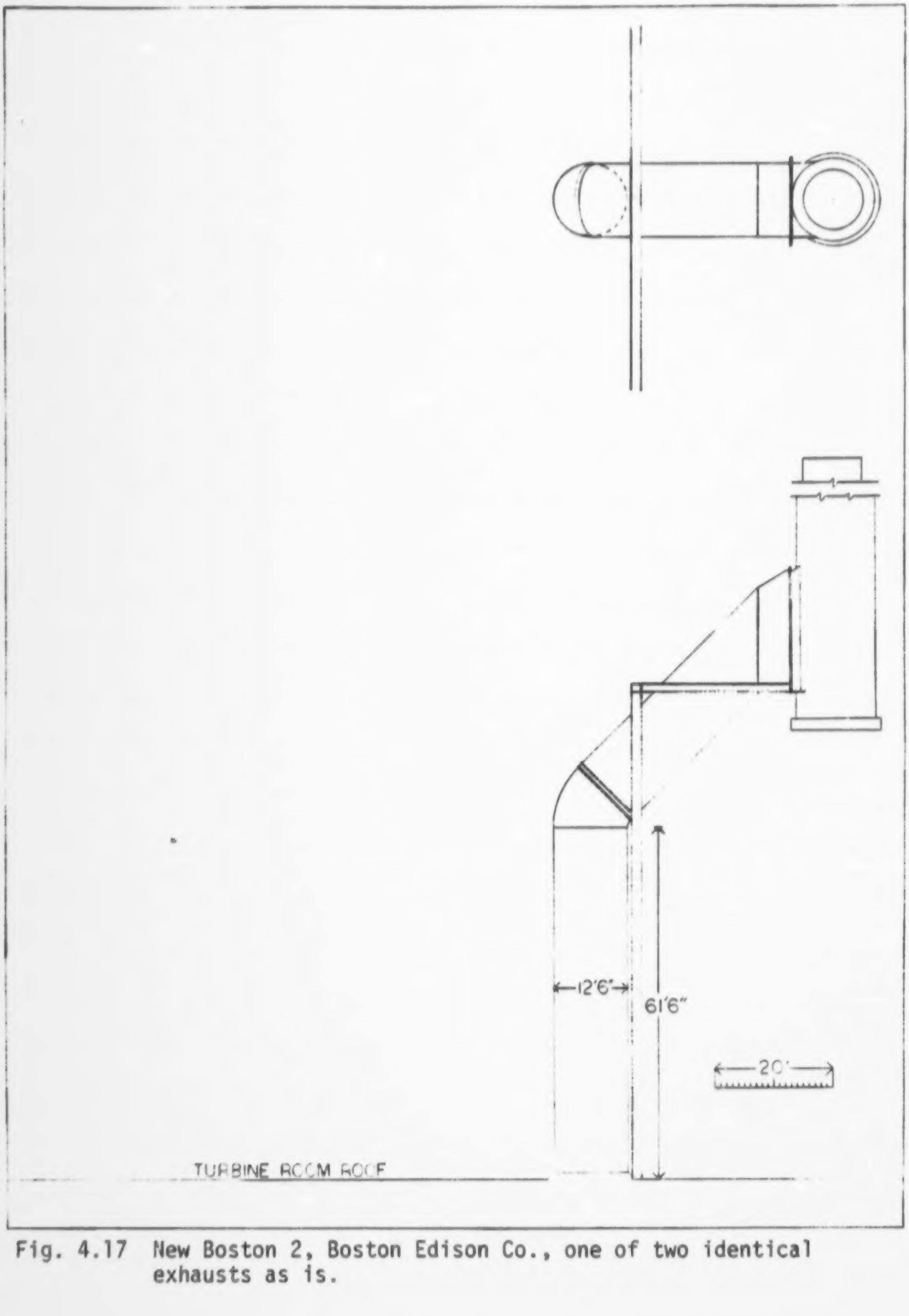

12'6"
61'6"
20'
TURBINE ROOM ROOF

Fig. 4.17 New Boston 2, Boston Edison Co., one of two identical exhausts as is.

to ponder the logistics of converting the New Boston units to coal. Unlike ESECA, the Fuel Use Act applies to units which have not previously burned coal but which can convert at a cost which is less than that specified by the cost test ratio (see section on Power Plant and Industrial Fuel Use Act). Since the prohibition on oil firing is discretionary to the Secretary of Energy under the Fuel Use Act, no clear picture can be constructed as to the standard of review which will be applied. Although the Charles T. Main study discussed in Chapter II concluded, "Converting this plant to coal does not appear to be practical", Edison personnel have requested that this study consider innovative options in the event that a conversion order is issued.

Alhtough a conversion to coal firing under the terms of the Fuel Use Act does not subject the facility to New Source standards, the facility must remain in compliance with all applicable state emission standards. The New Boston facility is subject ot a particulate emission standard of .12 lb/MMBtu and an SO_2 emission standard of .55 lb/MMBtu. Innovative hardware is reviewed in this section with respect to its capability for achieving these standards.

The SO_2 standard of .55 lb/MMBtu is difficult to achieve through the burning of low sulfur coal alone, and consequently SO_2 control would probably be desired. For three coal heating values the maximum allowed coal sulfur content is listed which achieves the .55 lb/MMBtu standard:

8,000 Btu/lb	.22%S
10,000 Btu/lb	.275%S
12,000 Btu/lb	.33%S

Although coals of this low sulfur content are available, they should be expensive and consequently the expense of SO_2 collection would be justified.

Sulfur dioxide is generally collected in a wet scrubber which requires many outside support systems such as pumps and reagent handling equipment. Due to the weight and vertical configuration of typical wet scrubbing systems, this device would probably be mounted on the ground adjacent to the turbine building, with the flue gas ducting extending from the roof, down to the ground, and subsequently back up to roof and to the stack. Depending on the alkali content of the flyash it might be desirable to remove flyash simultaneously in the wet scrubber, or if alkali content is low, before the wet scrubber with dust control equipment to reduce scrubber pump wear. There is little motivation to employ innovative particulate control hardware in the event that conventional wet SO_2 scrubbing is utilized. Consequently, the thrust of this investigation is toward approaches which could solve either the combined particulate and SO_2 control problem or the particulate problem alone (assuming the use of low sulfur coal), on the roof and spare the significant expense of ducting to the ground level and back.

Some uncertainty surrounds the value of design parameters which should be employed in providing the New Boston unit with particulate control equipment. Boston Edison personnel report that the unit presenlty displays a flowrate of approximately 1,000,000 acfm (500,000 acfm/stack) of flue gas in the stack ducting. This flowrate is on oil firing, and consequently the flowrate on coal firing should be less (for low and moderate volatile content coals). This number is not consistent with Stone and Webster unit design data which reports that at full load the flue gas mass flow should be 3.5×10^6 lb/hr. Utilizing the flue gas density reported in Appendix B for the coal listed, this mass flow rate would imply a flue gas flow of 1,102,000 acfm (270°F, atm). Edison personnel report that some errors have been found in the Stone & Webster data, and suggests that I utilize the 1,000,000 acfm value (although the unit design coal approximate analysis is similar to that reported in Appendix B, ultimate analysis is not provided and this could account for the 10% disparity).

Boston Edison personnel report that the pressurized New Boston units 1 and 2 are presently on the margin with respect to fan power, and consequently booster fans (probably ID) would have to be employed along with the use of any particulate control equipment, except for perhaps electrostatic precipitators. The present FD fans are capable of providing 30.2" WG of static pressure, while Stone & Webster data predicts that the supply air pressure at the airheater inlet at full load should be 21.5"WG. The extra 8.7"WG of pressure capability predicted has not been realized. Consequently, the innovative hardware designs would require that either the present FD fans be upgraded or that ID fans be employed. Since space for ID fans was not provided in the original boiler design, consultation with structural experts would be required before fans could be optimally positioned. Edison personnel suggested that design work for this study be completed without the depiction of additional fans. Fans would probably be employed atop the boiler support structure adjacent to the stacks, and consequently would not interfere with the control system designs suggested here which are all positioned above the turbine room roof. Due to the overhead crane employed in the turbine room, steel support structure can not be extended the 89'6" to ground level. Consequently collection equipment weight is an important consideration, and fans could almost certainly not be supported.

Electrofluidized Bed

The two-stage electrofluidized bed collector will provide an efficiency well in excess of that required to achieve the 0.12 lb/MMBtu particulate emission standard. The electrofluidized bed is not suitable for the employment of the dry SO_2 scrubbing technology, and consequently is designed with a low sulfur coal scenario in mind. An ionizer such as the high intensity ionizer can be employed between the two bed stages. The pressure drop of the electrofluidized bed is typically 8" WG per stage, and consequently ID fans would have to be utilized along with this technology. The employment of this technology is explored in Sec. 2.

Electrified Bed

The two-stage Electrified Bed is capable of providing an efficiency well in excess of that required to achieve the state particulate emission standard of 0.12 lb/MMBtu, and as discussed in this chapter in conjunction with Mystic 7, is well suited to employment of the dry SO_2 spray dryer collection technology, The collector exhibits an overall pressure drop of 6" WG, and allowing an additional 1" WG for flow through the spray dryer, a pressure deficit of 7" WG results. This deficit should be made up through the installation of an additional fan. The employment of this technology is explored in Sec. 2.

Wet Electrostatic Precipitator

The capability of the Fluid-Ionic collector for combined SO_2 and particulate collection makes it a potentially attractive system for employment at New Boston. The bottom half of each collector serves as a wet SO_2 scrubber while the upper half, which contains the wet electrostatic precipitator cylinders, serves the combined functions of particulate collection and mist elimination. It is essential that scaling be prevented in the collector, consequently a double alkali scrubbing solution should be employed. Equipment necessary for SO_2 collection other than the collector itself, such as pumps and water treatment, could conceivably be located at ground level adjacent to the turbine building.

The pressure drop requirement of the Fluid-Ionic collector is just 1" WG. Consequently the present fans could be either upgraded to provide the additional inch or a slight reduction in unit capacity could be accepted. The system weight is listed on Fluid-Ionic drawing #77217 as 30,145 lb/module when totally erected and filled with water.

The collection efficiency of the electrostatic precipitator section can be readily calculated through the use of the Deutsch equation. In the case of the 0.12 lb/MMBtu state standard, the collection efficiency of the cyclonic wet scrubber will contribute toward achieving the standard. The efficiency of the wet scrubber was ignored in the calculations performed for Mystic 7, since the emphasis in that case was on the collection of fine particles. The flowrate through the wet electrostatic precipitator (WESP) will be 432,000 acfm/stack due to the contraction which results after the 270°F stack gas is reduced to the wet bulb temperature. The design shown in Sec. 2 employs 4 modules/stack, with a resulting flowrate of 108,000 acfm/module. The modules depicted in Section 2 are scaled up from the modules described in Chap. III by 25% in all three dimensions, with a total increase in collection volume of 95.3%. Assuming that the collection of the wet scrubber serves to increase the effective plate collection area by 45%, integration over the size distribution of a typical coal (as described in Appendix A) yields a ratio of mass coming out of the collector to mass coming in of 2.51×10^{-2}. This transfer function is adequate for achieving the state standard on relatively clean 13,400 Btu/lb 8% ash coal. Consequently the collectors can be considered to be marginally adequate for achieving the state particulate emission standard, depending on the accuracy of the listed assumptions. It has been reported that laboratory SO_2 collection efficiencies as high as 90% have been reported for the Fluid-Ionic collector. This SO_2 collection efficiency is high enough to achieve the state emission standard when burning 10,000 Btu/lb, 2.75%S coal. The employment of the Fluid-Ionic collector at New Boston is further explored in Sec. 2.

Charged Droplet Scrubber

The charged droplet scrubber will in general be too heavy for roof top installation, and at ground level would provide little incentive for employment beyond that of a conventional wet scrubber. Since a conventional wet scrubber can be designed to achieve the 0.12 lb/MMBtu particulate emission standard, the charged droplet technology is not here considered for employment at New Boston.

Electrostatically Enhanced Bag Filter

The electrostatically enhanced bag filter is a large collector, similar to other baghouses, and consequently is not under consideration for the space and weight limited New Boston application.

2. Equipment Layout for Selected Innovative Technologies

a. Electrofluidized Bed Collector

Figure 4.18 illustrates the application of the electrofluidized bed collector at the New Boston facility. The collector module illustrated would serve one stack, so that two collection modules would be required per unit. The unit illustrated provides a total cross sectional area of 2,155 ft^2, which at a facial velocity of 325 fpm provides a 40% margin of extra space to account for partitions, feeders, insulation, and the like.

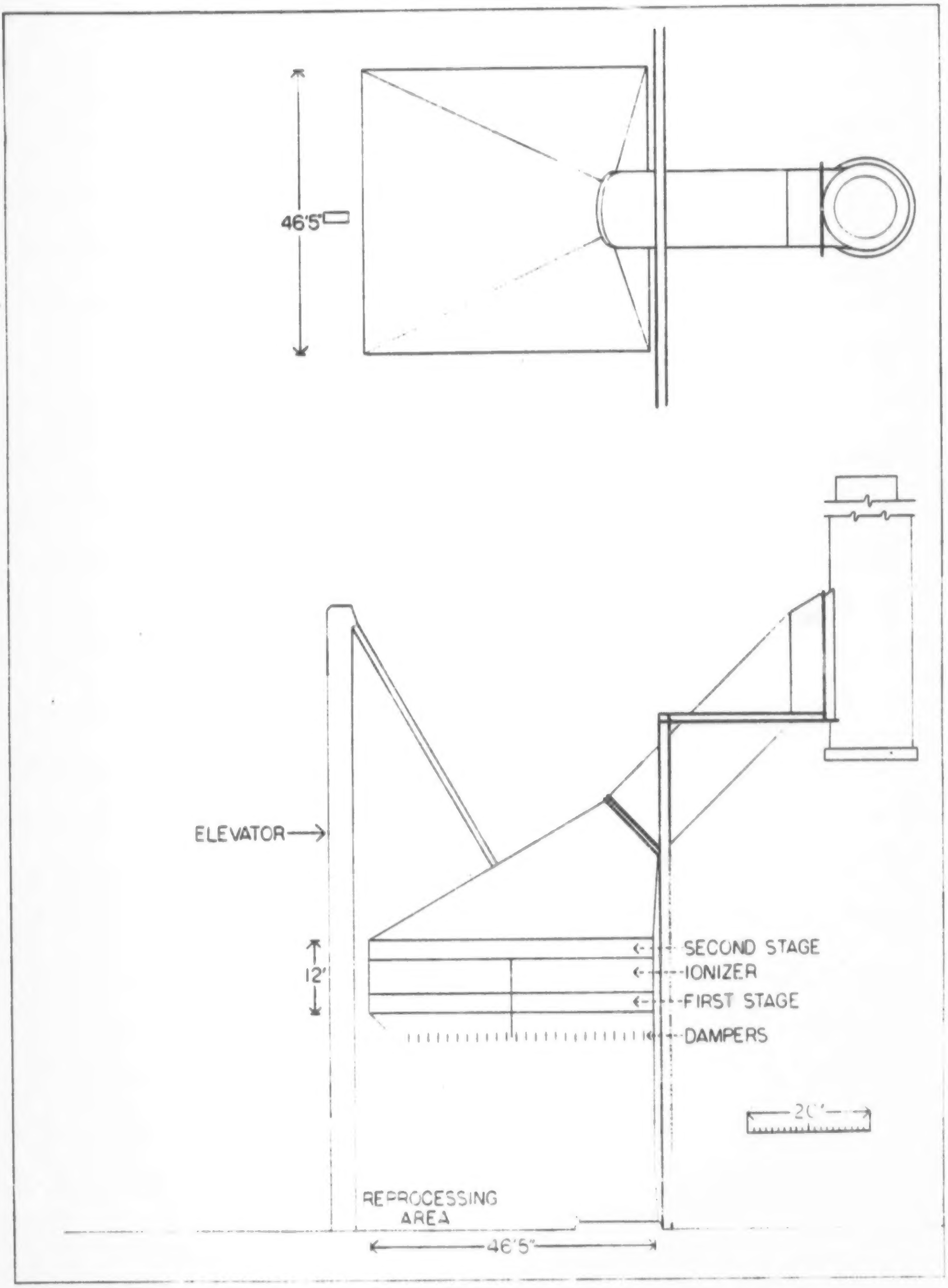

46'5"
ELEVATOR
SECOND STAGE
IONIZER
FIRST STAGE
DAMPERS
12'
20'
REPROCESSING
AREA
46'5"

Fig. 4.18 New Boston 2, Boston Edison Co., with two-stage electrofluidized bed collector.

The collector could be divided into four sections separated by dampers to accomodate unit turndown.

Additive injection is required in both the first and second stages to facilitate collector operation. Equipment for additive injection is not illustrated since an appropriate additive has not yet been identified for operation of the collector. Ionization is performed between the two stages since it is difficult to effectively ionize in the presence of the high ash loadings which result from uncontrolled coal combustion.

After bed particles have accumulated a significant coating of ash, typically doubling their weight, they must be removed from the boiler for reprocessing. The options with respect to reprocessing were discussed in Chapter III, with the logistics of sintering explored in the Mystic 7 section of this chapter.

b. Electrified Bed, Spray Dryer

Figure 4.19 illustrates the application of the Electrified Bed preceded by a spray dryer SO_2 collection system to the New Boston application. The operation of the spray dryer collector was discussed in this chapter with respect to the application at Mystic 7, The spray dryer can provide a collection efficiency of greater than 80% SO_2 removal through the injection of a stoichiometric quantity of either sodium carbonate or calcium hydroxide. An efficient downstream collector is required, since flyash loadings are typically doubled by the injection of reagent. In addition, it is helpful if the downstream collection device provides an effective contacting between reagent and gas. These requirements are easily met by the two-stage Electrified Bed. The Electrified Bed illustrated in Fig. 4.19 provides a roughing filter in the lower half. Gas passes into the center of the tubes which

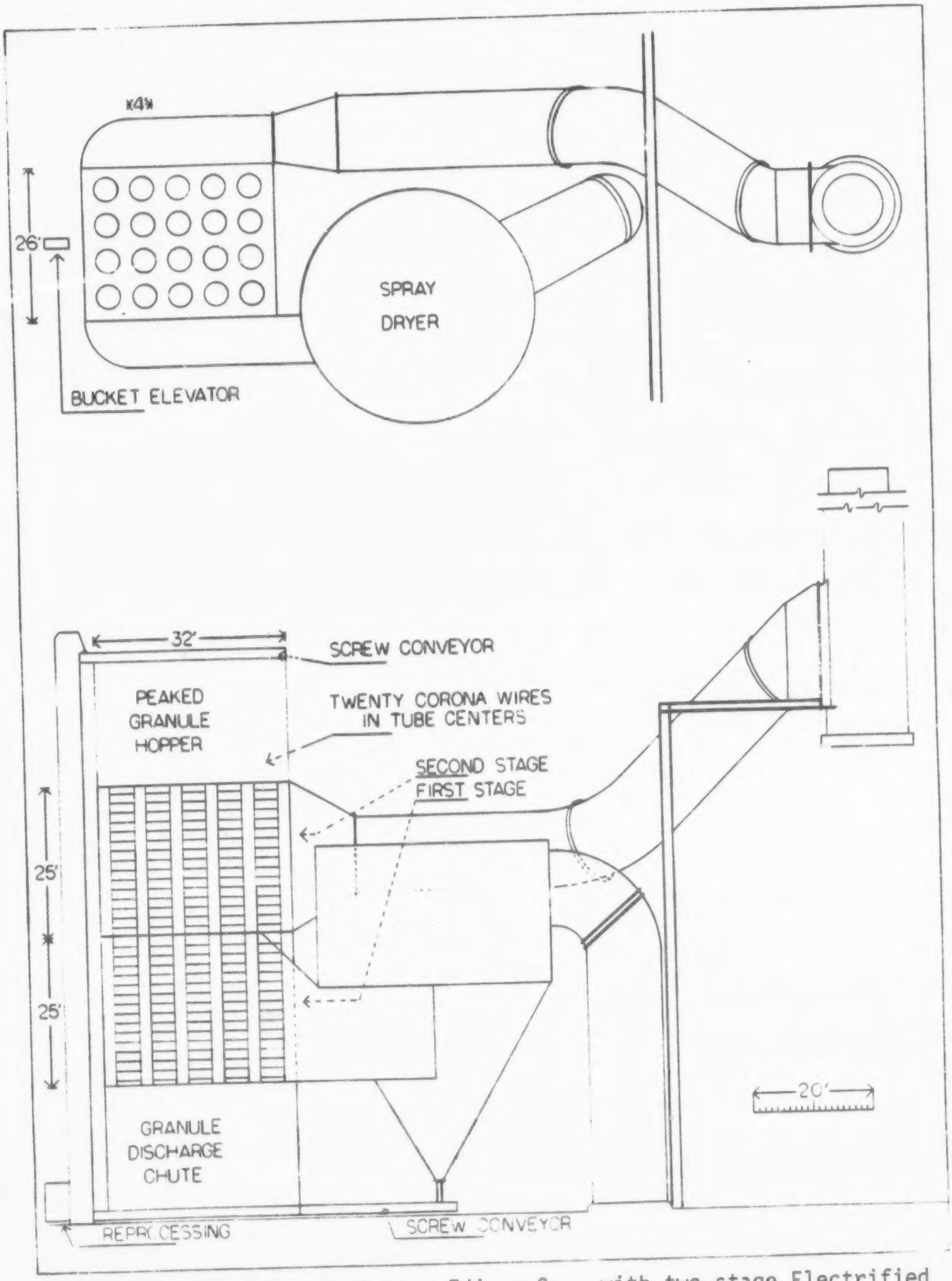

4'
26'
SPRAY
DRYER
BUCKET ELEVATOR
32'
SCREW CONVEYOR
PEAKED
GRANULE
HOPPER
TWENTY CORONA WIRES
IN TUBE CENTERS
SECOND STAGE
FIRST STAGE
25'
25'
GRANULE
DISCHARGE
CHUTE
20'
REPROCESSING
SCREW CONVEYOR

Fig. 4.19 New Boston 2, Boston Edison Co., with two-stage Electrified Bed and spray dryer SO_2 collection system.

contain corona wires. As gas passes up through the tubes the particulate is charged, and finally it passes out through the upper high efficiency collection stage. The collector illustrated provides 6,283 ft^2 of collection area in both the upper and lower stages to arrive at an effective facial velocity of 79.6 fpm.

Screw conveyors are provided for both the upper granule hopper and lower granule chute to reduce the required system height. The lower hopper of an Electrified Bed is often referred to as a chute, since each tube of the collector is provided with a vibratory feeder which runs slower than the capacity of the material handling and reprocessing equipment. Consequently, the lower chute is always empty. The reprocessing step consists of a small fluidized bed which entrains the collected material in an auxiliary gas stream (see Fig. 3.14). Ash and collected reagent can be conveniently conveyed to a storage silo distant from the collector. Auxiliary equipment required for operation of the spray dryer collection system is not illustrated in Fig. 4.19. This equipment could potentially be located at ground level adjacent to the turbine building. Since only a minimum of water is employed in the dry collection process the plant plume remains buoyant and no reheat is required.

c. Wet Electrostatic Precipitator

Figure 4.20 illustrates the application of the Fluid-Ionic wet electrostatic precipitator to the New Boston application. Four oversized collection modules are employed per stack as described earlier in this section to provide a particulate collection efficiency adequate for achieving the state standard. Module support structure and auxiliaries such as high voltage transformers are not illustrated in Fig. 4.20 since these would tend to com-

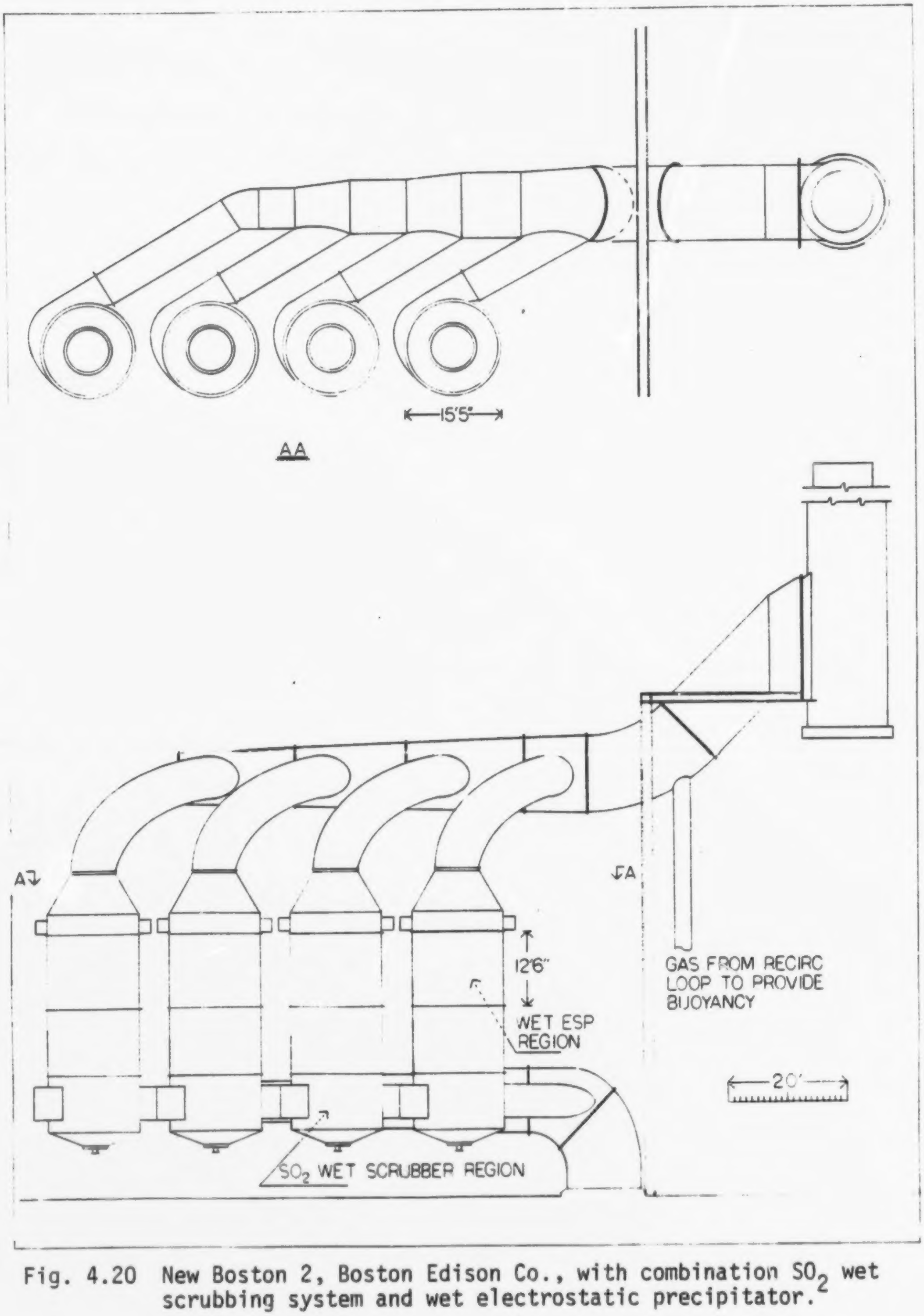

15'5"
AA
A
A
12'6"
GAS FROM RECIRC LOOP TO PROVIDE BUOYANCY
WET ESP REGION
20'
SO_2 WET SCRUBBER REGION

Fig. 4.20 New Boston 2, Boston Edison Co., with combination SO_2 wet scrubbing system and wet electrostatic precipitator.

plicate and obscure the drawing. The low 1" WG pressure drop of the modules implies that it would be desirable to provide small flow balancing dampers between the four collectors. Much of the required auxiliary equipment necessary for SO_2 collection could possibly be located at ground level adjacent to the turbine room.

Plume reheat would be required since the gas would become saturated after passing through the wet collectors. A potential means of providing reheat is illustrated in Fig. 4.20. Hot gas from the recirc loop could be ducted and mixed with flue gases before they reach the stack. This scheme is attractive since no additional fans would be required and dust collection is performed in the recirc loop. At full load recirc gas approaches 700°F in temperature and consequently only a small amount would be required. The small volume requirement implies that the overall SO_2 and particulate collection efficiencies will be only marginally affected.

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V. INNOVATIVE HARDWARE ECONOMICS

A. Summary of Available Cost Data

Several of the innovative technologies under consideration in this study have not been brought to the stage of commercialization, and none have been commercially employed in the power industry. Consequently, while cost data for conventional technology is available, cost data for innovative technology is generally not available. The capital costs of noncommercialized particulate control technologies are qualified in this chapter through a description of the components, materials, and assemblies required for operation. Capital costs are defined in this chapter as the sum of the purchase cost of the particulate collector, its supporting structure, any auxiliary equipment required for operation, and any extra ducting required to connect the collector to the powerplant. Capital costs are defined to be distinct from installation and indirect costs.

While installation cost data is available for conventional technologies, this data is not available for innovative technologies and estimates of this cost will be of little meaning at this preliminary stage. Installation data for conventional technology will be reviewed to calibrate the importance of this parameter in the overall cost. Indirect costs were defined in an EPA report to include the following items [1]:

1. Interest
2. Engineering costs
3. Field overhead
4. Freight
5. Off-site expenditures
6. Taxes
7. Spare parts
8. Shakedown

9. Contractor's fee and expenses
10. Contingency costs
11. Land cost

For the purposes of EPA cost estimates as well as those of many other engineering studies indirect costs (exclusive of land and contingency) are estimated to be 33.75% of the sum of capital and installation costs. Contingency is estimated as 20% of the sum of indirect, capital, and installation costs. Land costs must be considered on a case by case basis and are assigned no value in EPA cost estimates. Since indirect costs are generally assumed to scale linearly with direct costs (capital plus installation), it is not necessary to consider indirect costs in this study.

The operating costs of the various particulate control technologies are estimated and compared in this chapter. For EPA estimates, operating costs are classified under four headings [1]:

Utilities: includes water for slurries; and electricity for pumps, fans, valves, charging electrodes, rappers, compressed air systems, lighting, and controls.

Operating labor: includes supervision and the skilled and unskilled labor required to operate, monitor and control the system.

Maintenance and repairs: consists of both manpower and materials to keep the units operating efficiently. The function of maintenance is both preventative and corrective, to keep outages to a minimum.

Overhead: represents a business expense that is not charged directly to a particular part of a process but is allocated to it. Overhead costs include administrative, safety, engineering, legal, and medical services; payroll; employee benefits; recreation; and public relations.

Of these four categories only the areas of utilities and maintenance can be considered. Utility costs will be categorized and estimated for both conventional and innovative technologies. Materials required for operation such as replacement bags, and additive (in the case of the electrofluidized bed) will be categorized and assigned a costs value if possible.

1. Conventional Technology

The conventional technologies commonly employed by the utility industry are the electrostatic precipitator, and more recently the baghouse.

a. Electrostatic Precipitator

The capital costs of an electrostatic precipitator are specified in an EPA report to include the following components [1]: housing, discharge electrodes, collecting plates, distribution plates, rappers, T-R sets, insulators, bracing, supports, hoppers, and foundation. Information is available from several sources to help in estimating the cost of the sum of these components.

A study conducted by EPRI to assess the marketability of the high intensity ionizer provides a detailed study of information on the costs of modern electrostatic precipitators [2]. Data from this study was provided as Table 3.4, Table 3.11, Table 3.12, and Table 3.13. Table 3.13 provides a detailed cost breakdown for a large new ESP. In this study an efficiency of 99.5% was required for all cases, and four vendors were asked to submit material costs and specifications for collectors for use on both high and low sulfur coal. As can be observed from Table 3.4, the vendors suggested a wide variation in plate areas to achieve the standard, and a significantly larger plate area for use on low sulfur than for use with high sulfur coal. The 99.5% efficiency level is consistent with the efficiency which was required for achieving the benchmark standard in Appendix A, but may not provide a sufficient safety margin for achieving the new source performance standard for some utilities. Bids were accepted in all cases for a total cold-side flowrate of 2×10^6 acfm. An assumption was made throughout the study that installed cost would be double the total material and equipment costs.

It seems unlikely that utilities in New England will be burning either the high sulfur or low sulfur coals specified in Table 3.4. There has been much regional discussion concerning the possibilities of burning 1.5%S coals, and in the Chapter 4 discussion on the Brayton Point facility it was concluded that an SCA of slightly less than 400 ft^2/1000 acfm would be required for achieving the benchmark standard when burning 1.5%S coal. Table 5.1 taken from the EPRI study predicts how collector costs scale with total plate area from the responses of the four vendors.

TABLE 5.1

Cost of electrostatic precipitator as a function of total collecting surface area (ft^2) in 1975 dollars

VENDOR	INSTALLED COST ($/$ft^2$ plate area)
A	$5.08 - 7.0 \times 10^{-7}a$
B	$5.60 - 1.0 \times 10^{-6}a$
C	$3.64 + 1.2 \times 10^{-7}a$
D	$8.22 - 7.7 \times 10^{-7}a$

Costs reported in the EPRI study are in 1975 dollars, consequently a scaling factor must be utilized to update costs to 1980 dollars. An inflation rate of 10%/year is typical for pollution control equipment, consequently cost figures must be multiplied by a factor of 1.61. Costs in this chapter are calculated on a per acfm basis, with flowrates referenced to a stack gas temperature of 300°F. Cost data reported in Table 5.2 is calculated from the data in Table 5.1 for both a collector of 4×10^5 ft^2 (10^6 acfm or approximately 350 MW$_e$) and a collector of 8×10^5 ft^2 (2×10^6 acfm or approximately 700 MW$_e$).

TABLE 5.2

Material and equipment cost in dollars per acfm for 1980 dollars from four vendors and for two electrostatic precipitator sizes.

Vendor	Precipitator plate area (ft^2) 4×10^5	 8×10^5
A	\$3.09/acfm	\$2.91/acfm
B	\$3.35/acfm	\$3.09/acfm
C	\$2.38/acfm	\$2.41/acfm
D	\$5.09/acfm	\$4.90/acfm

Another source of current data on electrostatic precipitator capital costs is provided by a paper from the Bechtel Power Corp. which reports their experience in choosing between a hot-side ESP, cold-side ESP, or baghouse for use on the boiler of a Southwestern utility installation [3]. The utility under study was planning to burn coal with a low sulfur content (as low as 1/4%), and consequently relatively large cold-side precipitators were recommended by the manufacturers. Bechtel engineers specified a collector efficiency of 99.84%, somewhat higher than would be required for the utilization of the moderate ash content, 1.5%S coals envisioned for use in the New England area. Consequently the average SCA must be reduced from the 739 ft^2/1000 acfm of the study to the nominal 400 ft^2/1000 acfm value considered adequate for the applications of this report.

The Bechtel study reports an average cost of \$6.25/ft^2 of collector plate area in 1980 dollars. Multiplying by the collector SCA of 400, a collector price of \$2.50/acfm results. This value should be somewhat low due to the economies of scale which result as ESPs grow larger. A correction factor can be calculated from Table 5.1, and an ESP capital cost of approximately \$3.00/acfm results. The Bechtel study also reports that installation costs for cold-side ESPs averaged just 59% of the capital costs. This value is lower than the factor of 2 quoted in the EPRI study, and can possibly be accounted for by the large ESP sizes studied by Bechtel.

A third source of information on ESP cost is provided by the EPA support document which accompanied the revised new source performance standard [4]. This study quotes collector plus installation prices in 1980 dollars for a range of collector and plant sizes. For a collector with an SCA of 360 ft^2/1000 acfm on a 500 MW plant, an installed capital expenditure of \$31.82/kw is reported. This capital expenditure figure incorporates roughly a factor of 2 for installation, a factor of 1.3375 for indirect costs, and a factor of 1.2 for contingency. Separating out these factors and dividing by the 2.94 acfm/kw gas to power generation conversion factor from Appendix B results in an equipment capital cost of \$3.37/acfm for the 360 SCA collector. Straight line projection out to the 400 SCA size considered here results in a collector capital cost of \$3.75/acfm in 1980 dollars.

Six items can be readily identified as utility requirements for electrostatic precipitators:

Corona power: The electrical energy imparted to ionization in an electrostatic precipitator represents a significant expense for the use of this technology. A typical ESP electrical utilization is 0.7 watt/acfm. There are several different formulas used to estimate the internal costs to utilities of electric power utilization. A conservative technique is to estimate that this cost is the same as the purchase cost of the fuel required for generation, although the real cost is higher. Oil contains 148,000 Btu/gal and sells for approximately $18/barrel (42 gallons). Assuming a heat rate of 10,000 Btu/kwhr, a price for the electricity used internally by a power facility of 2.9¢/kwhr is derived. Consequently, corona power costs approximately .002¢/acfm·hr for a typical electrostatic precipitator.

Draft loss: A well designed electrostatic precipitator will require somewhat less than 1" WG of pressure drop. Assuming a 75% efficiency for the fan and motor combination, an electrical power requirement can be estimated for supplying the 1" WG. Taking the product of pressure and flowrate, a pressure drop power requirement of .11 W/acfm is calculated. Adjusting this value for the fan efficiency, a draft power consumption of .15 W/acfm is predicted. Using the electricity cost derived above, a draft energy expense of 4.4×10^{-4} ¢/acfm·hr is calculated.

Ash eductors, rappers, insulator purge air: Small amounts of electrical power are required in ESP operation to power the ash handling system, rappers, and for the injection of hot purge air around high voltage insulators. The sum of the utilization of these three systems should be small compared to the first two mentioned points, and consequently the cost of this consumption can be ignored.

The sum of the listed energy cost for corona power and draft loss is .85 W/acfm. This translates to an energy cost of .0025 ¢/acfm·hr according to the previously discussed methodology.

b. Baghouse

The capital costs of a utility baghouse are specified in an EPA report to include the following components [1]: housing, bag supports, bags, shakers or reverse air system, thermal insulation, bracing, supports, hoppers, foundation, ducting, and ash removal system. Information is available from two sources to provide an estimate of baghouse capital cost.

The previously mentioned Bechtel study solicited technical and cost data from a number of baghouse manufacturers and reports the average of the responses [3]. The average recommended air to cloth ratio from eight manufacturers is 2.37 ft/min. With an average purchase price of \$7.1/ft^2 of bag area, a baghouse cost of \$3.00/acfm in 1980 dollars is predicted. Baghouse size is not dependent on fuel properties, and baghouse cost does not scale as strongly with collector size as electrostatic precipitator cost [5]. Consequently, this figure can be applied to a range of utility facilities with only minor adjustments required for installation size. Bechtel reports that on the average the installation costs quoted by manufacturers amount to 51% of the collector purchase cost.

The EPA support document for the revised new source performance standard specifies that utility baghouse have an air to cloth ratio of 2 ft/min [4]. EPA data reports the total installed cost of pollution control hardware, including equipment costs, installation, indirect costs, and contingency. Indirect costs as well as contingency costs are specified by EPA, and a reasonable assumption is that installation costs are equal to equipment costs. Using the gas flow to power generation conversion factor of 2.93 acfm/kw from Appendix B and separating out equipment costs from the total provides Table 5.3 from the EPA data.

TABLE 5.3

Baghouse capital cost as a function of installation size in 1980 dollars.

Boiler Size (MW)	Capital Cost (\$/acfm)
200	6.35
500	5.49
1000	4.95

Note the small variation in baghouse capital cost with plant capacity. The variation reported in Table 5.3 should be partially caused by the improvement in heat rate realized by larger generation facilities. This improvement is not reflected in the conversion factor taken from Appendix B (in Appendix B a heat rate of 10,000 Btu/kwhr is assumed).

Draft loss represents the bulk of the energy penalty required by a baghouse collector. Other components require energy such as the ash handling system and the bag regeneration system, but this requirement should be small (with the exception of pulse-jet collectors, not commonly employed in the utility industry, which require significant quantities of compressed air).

Baghouses are typically specified to operate at less than 5" WG pressure drop. Assuming a 75% fan efficiency this translates to an electrical power consumption of .76 W/acfm. At a cost of 2.9¢/kwhr, an energy cost for draft loss of 2.1×10^{-3} ¢/acfm·hr is predicted.

A significant cost in baghouse operation is the materials and labor required to replace bags on a continuous basis. Since baghouses have only recently been employed on utility installations, reliable data on the cost of bag replacement is not yet available. Most baghouse manufacturers claim a bag lifetime of approximately three years.

2. Innovative Technology

a. Electrofluidized Bed

The electrofluidized bed can be employed in both a collector and an agglomerator mode. Most of the capital components are common to both technologies. These common components are listed and described below:

Housing.

Distributor plates, should be of wear resistant material.

Bed electrodes, spaced above the distributor plate with insulators.

Charging elements, in the gas stream before the distributor plate if required. Charging elements must be insulated for high voltage and can employ wires and plates, or equivalent.

Dampers, required to maintain sufficient flow velocity in the collector during unit turndown.

Additive injection equipment, not yet developed but fundamentally a spray nozzle system positioned above the distributor plates.

Granules, bed material of sand or equivalent (a small cost).

Plenums,

Ducting,

Foundation,

Transformer-rectifier sets, required to impose an electric field across both the bed and the charging elements if employed.

Rappers, required for distributor plate and charger if employed.

Most of the energy requirements of electrofluidized bed systems are common to both embodiments. Common energy requirements are listed below:

Bed electric field, a high voltage electric field is employed across the sand bed to electrically polarize the bed material. The energy requirement to supply this electric field can shift from negligible to prohibitive, depending on the nature and amount of ash carbon content.

Charging current, the .06 watt/acfm power requirement of the high intensity ionizer provides an estimate of the energy requirement for one-time charging.

Rappers, purge air, additive injection; small energy requirements for the use of both electrofluidized bed configurations.

Draft loss, fluidized bed pressure loss is equal to the gravitional force which bed material exerts on the distributor plate in the absence of gas flow. Since a 10 cm bed height is required to provide adequate efficiency, if sand is utilized a bed material pressure drop of 5.9" WG will result.

Loosely packed dry sand displays a bulk density which ranges between 1400 and 1700 kg/m^3 [6]. In addition to the pressure loss of the sand bed itself, the pressure loss of the distributor plate, plenums, and any external required equipment must be added to the total. This pressure drop sum for the one-stage fluidized bed can be estimated to be 8" WG. This amounts to an energy utilization of 1.21 W/acfm or a cost of .0035 ¢/acfm·hr according to the previously discussed methodology.

i. Collector

In addition to the capital components listed above which are common to both the collector and the agglomerator, the collector requires the following listed equipment for operation:

Feeders, a material feeder is required below each distributor plate section to meter ash coated bed material to the regeneration process.

Regneration system, a system which either strips the ash coat off the surface of bed material, or sinters, crushes, and sorts ash coated particles to generate fresh bed material (these options are discussed in Sec. IVC).

Material handling equipment, required to carry spent bed material away from the collector and return fresh material.

Three important unknowns must be addressed by future developers of the electrofluidized bed collectors. The most important question surrounds the feasibility and economics of employing an additive to promote ash adhesion. As of this date, an additive with a suitable viscosity for collector operation at stack temperatures has not been identified.

A second unknown is the amount of pressure drop required to achieve even fluidization across the large diameter fluidized beds required to accommodate a powerplant flue gas stream. Fluidized beds of this scale have not as yet been built, consequently data on the minimum pressure drop required is not available. Scaleup is a significant unknown for this technology.

The power requirement of imposing an electric field across a fluidized bed can range from negligible to prohibitive, depending on the degree to which ash carbon contributes to bed conductivity. This question can be effectively addressed through pilot plant studies.

The energy to operate material handling and regeneration equipment is required for collector but not agglomerator operation. Data reported in Table 4.1 predicts that in order to sinter collected ash a heat burden of 0.8% of the boiler net heat input rate must be accommodated. Since additive and regeneration technologies have not yet been developed, it is not possible to speculate at this time as to their eventual energy requirements.

In the event of a new installation or in the case where no pollution control equipment is presently in place, two-stage electrofluidized bed collectors are proposed. A one-stage electrofluidized bed collector is not well suited to operation in the presence of the high ash loadings typical of uncontrolled coal combustion. The pressure drop of the two-stage electrofluidized bed collector should be somewhat lower than double the pressure loss of the one-stage collector. When two beds are utilized in series the heights of each can be reduced to provide a given efficiency, and the required pressure drop through each distributor plate should be lower. Consequently, a two-stage system pressure loss of 14" WG is predicted. This amounts to an energy utilization of 2.11 W/acfm or a cost of .0061 ¢/acfm·hr according to the previously discussed methodology. Other elements of the collector energy requirement contain too high of an uncertainty to derive a total.

ii. Agglomerator

The capital components of the agglomerator system are common to both embodiments and have already been listed. The special problems previously listed with respect to the collector are common to both systems except for the question of additive. Alexander found that #6 fuel oil provided an additive suitable for agglomerator operation. There are many questions concerning the feasibility of using fuel oil as an additive. Some of these include the cost, the possibility of hydrocarbon and odor emissions, and the potential problem of explosion. Consequently, additional research is required into the problems of additive usage for the agglomerator as well as for the collector.

The energy requirements of the agglomerator have already been described, since they are common to both embodiments. The energy requirement of the agglomerator is dominated by the fan power required to overcome the 8" WG pressure loss, and the requirement for bed electrical energization. Data is not available concerning the magnitude of this latter expense.

b. Electrified Bed

The capital components of the one-stage and two-stage Electrified Bed collectors are identical except in the area of ionization equipment. The capital components of both configurations are listed and described below:

Housing,

Collection tubes, concentric cylinders which consist of vertically arranged louvers on the inner and outer face, with a high voltage cylindrical electrode suspended by insulators between the two cylinders.

Charging elements, this item consists of a wire suspended by insulators in the center of two-stage collector cylinders, and could consist of an ionizer such as the high intensity ionizer for one-stage collectors. When the Electrified Bed is employed following an ESP an ionizer may not be required.

Feeders, a vibratory feeder is required beneath each collection tube to meter ash coated bed material to the reprocessing system.

Material handling equipment, equipment is required to transport bed material to the reprocessing system and back to the collector. Generally a single bucket elevator will be sufficient for handling both tasks, but in the case of wide systems the use of supplementary screw conveyors could be warranted.

Regeneration equipment, this system is detailed in Fig. 3.14 and consists of a small fluidized bed which entrains the ash in a small auxiliary gas stream. The auxiliary gas stream can be ducted to the ash storage bin which should be sealed and equipped with a bin-vent dust collector.

Granules, rappers; filling the collector with granules should represent a small expense. If charging wires are utilized one rapper per tube should be employed.

Transformer-rectifier sets, T-R sets are required both for charging and imposing an electric field across the granular bed.

The energy requirement of the Electrified Bed is primarily due to pressure drop and the requirement for high voltage electrical energization. The various energy consuming components are listed below:

Draft loss, the Electrified Bed from flange to flange requires 3" WG per stage. This amounts to an energy utilization of .45 W/acfm per stage or an equivalent cost of .0013 ¢/acfm·hr according to the previously discussed methodology.

Charging current, if charging is required power consumption should be similar to the .06 watt/acfm consumption of the high intensity ionizer.

Purge air, rappers; these represent a minimal energy requirement.

Material handling equipment; the electricity required to operate material handling equipment is small compared to that required for ionization and fan power. Assuming a gas ash loading of 3 gr/aft^3, an elevator height of 150', and an elevator plus motor efficiency of 60% [7], an elevator energy requirement to convey the required bed material of .025 W/acfm is predicted. This is just 6% of the draft loss energy requirement of the one-stage collector.

Regeneration fan and bin-vent, the regeneration loop operates with a pressure requirement of approximately 15" WG. Since this auxiliary gas stream volume amounts to at most 5% of the primary flue system volume, the energy requirement for driving this system should be 25% of the draft loss cost for a one-stage collector, and 12.5% of the draft loss cost for a two-stage collector. The energy requirement of the bin-vent, other than for pressure drop, is negligible.

Bed electric field, the required bed electric field is highly dependent on ash carbon content and consequently is hard to predict without the benefit of further pilot plant studies. Tests conducted at GM on the emissions from a stoker fired boiler operating at reduced load (conditions which lead to extremely high carbon levels) demonstrated fluctuations in this power requirement from negligible to .1 watt/acfm. Consequently the value of .1 watt/acfm provides a conservative value for power supply design.

A conservative sum of the energy requirements for the two-stage Electrified Bed is 1.2 W/acfm. This total includes power required to supply pressure drop, for material handling equipment (to a height of 150'), corona power, bed power, and to power the material regeneration loop. This consumption translates to a cost of .0035 ¢/acfm·hr at a price for electricity consumed of 2.9 ¢/kwhr.

A conservative sum of the energy requirements for the one-stage Electrified Bed is 0.7 W/acfm. This total is less than for the two-stage collector due to the lower system pressure drop and the exclusion of the .06 W/acfm requirement for corona charging. This consumption translates to a cost of .0020 ¢/acfm·hr at an electricity price for internal use of 2.9 ¢/kwhr. The Electrified Bed is the product of, and is being marketed for a wide variety of applications by EFB, Inc. of Woburn, MA. Dr. Alexander, research engineer at EFB, Inc. reports that a 50,000 acfm flyash collector is currently under construction and is scheduled for startup in 1980. Dr. Alexander reports that current fabricator cost data places the sale price of a utility scale two-stage Electrified Bed collector, including all required auxiliaries, at $2.00/acfm (1980 dollars). A one-stage collector can be provided, in Dr. Alexander's opinion, for $1.00/acfm.

c. High Intensity Ionizer

Table 3.10 reports the estimated cost of the HII array as taken from the previously discussed 1975 EPRI study (see Sec. IIID). A factor of 1.61 translates the reported figures from 1975 to 1980 dollars. From the table a capital cost of $1.45/acfm is predicted.

A special problem in the use of the HII technology, as reported in Sec. IIID, is the loss of charge through induced corona effects which result when the ionizer is subjected to high ash loadings.

The pressure drop requirement of the HII is reported to be 1/4"WG, or approximately .04 watt/acfm. The electrical power requirement of the ionizer is reported in Sec. IIID to be .06 watt/acfm. The sum of these two energy requirements can be assigned a cost of 2.9×10^{-4} ¢/acfm·hr according to the previously discussed methodology.

d. Electrostatically Enhanced Bag Filter

The Apitron electrostatically enhanced bag filter consists of a baghouse mounted atop a small electrostatic precipitator (Fig. 3.24). Auxiliary equipment required for operation includes transformer-rectifier sets, ash eductor equipment, and an air compressor required for the pulse-jet cleaning process. Fig. 3.21 shows that a cooling system is required to control fly-ash resistivity. In lieu of an appropriate fresh water source, a cooling tower would be required.

Apitron personnel have stated that the capital equipment required for Apitron operation can be purchased at the same cost as a conventional utility fabric filter system. In this chapter the capital cost of a utility fabric filter collector was reported as $3.00/acfm from one source and $5.49/acfm from another.

A special problem anticipated for Apitron operation is the expense of operating a pulse-jet collector with felted teflon bags. Felted teflon is extremely expensive and must exhibit a long lifetime to prove cost effective. In addition, temperatures in the baghouse must be prohibited from reaching 450°F to protect the fabric.

The energy requirements of the Apitron collector are listed below:

Draft loss, reported in Table 3.14 as 1.5" WG for the mobile test unit. This translates to an electrical power consumption of .23 watt/acfm.

Charging current cost, reported in Table 3.14 as approximately 1 watt/ acfm.

Water pump, ash eductor; the power requirements of these systems should be relatively small.

Air compressor, Apitron reports that .0012 scfm of compressed air at 80 psig is required per acfm of flue gas treatment. This translates to an electrical power consumption for bag cleaning of .18 W/acfm [8].

The sum of the listed power requirements for the Apitron collector is 1.41 W/acfm, which translates to a cost of 4.1×10^{-3} ¢/acfm·hr by the previously discussed methodology.

e. Wet Electrostatic Precipitator

The Fluid-Ionic wet electrostatic precipitator (WESP) consists of a concentric cylinder type electrostatic precipitator mounted atop a cyclonic wet scrubber (see Fig. 3.28). In addition to the collector system itself, a transformer-rectifier set and hot air purge system is supplied with the collector. A water circulation and retreatment system would also be required for WESP operation on a utility installation.

The WESP system is constructed almost entirely of FRP and hastelloy, and consequently is expensive. Fluid-Ionic reports that the sale price for one of their WESP modules is $350,000. In Sec. IVE it was concluded that each WESP module, to achieve a moderate efficiency, can handle no more than 64,000 acfm (referenced to 300°F stack temperatures, flow in the module is less due to the cooling effect of the water). To achieve this moderate efficiency, a capital cost for the collector of $5.47/acfm is required.

The effectiveness of the WESP for combined particulates and SO_2 control could be limited by the requirement for a low level of suspended solids. The feasibility of using the system for combined collection is currently undergoing EPA sponsored investigation.

At a flowrate of 64,000 acfm (referenced to stack temperatures) the energy requirements of the wet collector can be calculated. The energy requirements include .31 watt/acfm for high voltage and the purge air system, .15 watt/acfm to supply the 1" WG pressure requirement, and an energy penalty suffered due to the need for plume reheat.

To achieve acceptable plume buoyancy a reheat of approximately 100°F must be employed. This level of reheat requires approximately 1.71 Btu/ft^3. If this heat is provided through burning fuel, an electrical energy equivalent consumption of 10.26 W/acfm would result (using a plant heat rate of 10,000 Btu/kwhr). In the temperature range of interest, low grade heat can potentially be utilized. Consequently, this energy cost should be considered as worst case.

The energy requirement of the WESP collector, exclusive of plume reheat, is .46 watt/acfm. This translates to an energy cost of .0013 ¢/acfm·hr at an electric energy price of 2.9 ¢/kwhr. The energy requirement becomes 10.72 watt/acfm if the plume reheat requirement is included. This translates to an energy cost of .031 ¢/acfm·hr at an electric energy price of 2.9¢/kwhr.

f. Charged Droplet Scrubber

The charged droplet scrubber (CDS) is not commercially available at this time and consequently capital cost data is not available. The capital components of the system are illustrated in Fig. 3.30 and listed below:

Ionization section, includes charging elements similar to a small ESP.

Spray tower, consists of an open chamber with numerous spray nozzles insulated for high voltage operation.

Mist eliminator, to remove droplets from the gas stream.

Pumps, for circulation of water. In the present University of Washington configuration circulation pumps are isolated for high voltage operation.

Transformer-rectifier sets, required for charging droplets, powering the corona ionizer, and operation of an electrostatically enhanced mist eliminator.

Purge air system, in a wet environment a significant quantity of purge air is required to maintain high voltage insulation.

Water treatment, a system must be provided to separate the collected ash from process water.

Similar to the wet electrostatic precipitator a charged droplet scrubber must be constructed of corrosion resistant material such as FRP and hastelloy. The development of a nonfouling technique for the charging of droplets is an important area for CDS development. Direct charging of droplets can be employed through holding the water feed pumps at high voltage, but this technique may not prove to be workable for a full-scale installation. Maintaining insulation quality in a wet environment also promises to be a challenging engineering problem.

The energy requirements of the charged droplet scrubber are described below:

Draft loss, pressure drop in the charged droplet scrubber is highly dependent on system design. A value of 3" WG should be nominal, or approximately .45 watt/acfm.

Purge air, the purge air system utilized by Pilat consumes .443 Btu/aft^3

of flue gas. Presumably low temperature heat could be provided from a source other than electric heating. If fuel is used to supply this heat, an equivalent electrical energy consumption of 2.66 watt/acfm will result (using a plant heat rate of 10,000 Btu/kwhr, and normalizing flow to the 300°F nominal stack temperature).

Pumps, the pump utilized by Pilat during one-stage collector operation supplied 12 gpm at 95 psig. This amounts to an electrical utilization of .39 watt/acfm assuming an 85% pump plus motor efficiency.

High voltage power, during the Centralia tests the University of Washington Electrostatic Scrubber consumed approximately 1.29 watt/acfm of high voltage power.

Plume reheat, to achieve acceptable plume buoyancy a reheat of approximately 100°F must be employed. This level of reheat requires approximately 1.71 Btu/aft^3. If this heat is provided through burning fuel, an equivalent electrical energy consumption of 10.26 W/acfm would result (using a plant heat rate of 10,000 Btu/kwhr).

The total energy requirement of the charged droplet scrubber, exclusive of plume reheat, is 4.79 watt/acfm. This translates to an energy cost of .014 ¢/acfm·hr at an electrical energy price of 2.9 ¢/kwhr. If plume reheat is added to this energy requirement, the sum becomes 15 W/acfm at a cost of .044 ¢/acfm·hr.

B. Comparison of Cost Data for Meeting Plant Requirements

1. Listing of Innovative Technologies Suitable for Individual Plant Requirements

The six innovative technologies were analyzed in Chapter IV with respect to their potential for solving the individual plant requirements. A summary of that analysis is provided in Table 5.4a,b. The conclusions of the next five sections are based upon the technical data presented in Chapter IV and the economic data already presented in this chapter.

2. Mt. Tom

The electrofluidized bed collector and Electrified Bed have been chosen as potential candidates to retrofit the Mt. Tom ESP for coal firing. Previous discussions indicate that the present ESP size of 75 ft^2/1000 acfm would have to be increased by a factor of greater than four to bring the emissions safely within the guidelines set by the conversion program at Brayton Point. The one-stage Electrified Bed with a capital cost of approximately $1.00/acfm provides an alternative which is comparable to or less expensive than adding additional ESP volume (approximately $2.00/acfm). Additional savings are anticipated in the area of installation, since the incremental ESP volume would have to be installed on the opposite side of the stack due to space limitations. Comparable capital cost savings could be realized through use of the electrofluidized bed, although this system has not yet been commercialized and data is not available.

The lower installed cost of the Electrified Bed with respect to the electrostatic precipitator could be offset by a capital expenditure required for upgrading the present fans. The required additional ESP volume with its attendant ducting should require on the order of 1" WG additional

TABLE 5.4a Listing of Innovative Technologies Suitable for Individual Plant Requirements

Plants / Technologies	Mt. Tom	Middletown 3	Mystic 7
Electrofluidized Bed Collector	Yes, downstream from the present electrostatic precipitator	No, insufficient space available.	Yes, two-stage collector required. No SO_2 control provided.
Electrofluidized Bed Agglomerator	No, insufficient space available.	Yes, upstream from the present electrostatic precipitator.	No, not appropriate since technologies are here considered for replacement rather than retrofit.
Electrified Bed	Yes, one-stage collector incorporated into the present ESP exit plenum.	Yes, a one-stage collector incorporated into the present ESP exit plenum.	Yes, two-stage collector with spray dryer to provide combined particulate and SO_2 control.
High Intensity Ionizer	No, ESP facial velocities too high.	No, ESP facial velocities too high.	Yes, in conjunction with electrofluidized and one-stage Electrified Beds.
Electrostatically Enhanced Bag Filter	No, insufficient space available, preferentially a replacement technology.	No, insufficient space available, preferentially a replacement technology.	Yes, could provide simultaneous SO_2 control with spray dryer alkali injection.
Wet Electrostatic Precipitator	No, wet collection not desirable in lieu of requirement for FGD.	No, wet collection not desirable in lieu of requirement for FGD.	No, not sufficiently efficient to achieve particulate NSPS standard.
Charged Droplet Scrubber	No, wet collection not desirable in lieu of requirement for FGD.	No, wet collection not desirable in lieu of requirement for FGD.	Yes, to provide simultaneous particulate and SO_2 control.

TABLE 5.4b Listing of Innovative Technologies Suitable for Individual Plant Requirements

Plants Technologies	Brayton Point 2	New Boston 2
Electrofluidized Bed Collector	Yes, downstream from the present electrostatic precipitator.	Yes, two-stage collector required. No SO_2 control provided.
Electrofluidized Bed Agglomerator	Yes, upstream from the present electrostatic precipitator.	No, not appropriate for unit without pollution control equipment presently in place.
Electrified Bed	Yes, one-stage collector incorporated into present ESP exit plenum.	Yes, two-stage collector with spray dryer to provide combined particulates and SO_2 control.
High Intensity Ionizer	Yes, incorporated into the present ESP inlet plenum.	Yes, in conjunction with the electrofluidized bed collector.
Electrostatically Enhanced Bag Filter	No, insufficient space available.	No, insufficient space available.
Wet Electrostatic Precipitator	No, wet collection not desirable in lieu of requirement for FGD.	Yes, to provide combined wet SO_2 and particulates control.
Charged Droplet Scrubber	No, wet collection not desirable in lieu of requirement for FGD.	No, insufficient space available.

pressure drop, while the one-stage Electrofluidized Bed requires 3" WG pressure drop. The one-stage electrofluidized bed illustrated in Fig. 4.2 requires a pressure drop of 8" WG to operate.

The energy consumption of an Electrified Bed and ESP retrofit at Mt. Tom would be roughly comparable (including incremental fan power). The one-stage Electrified Bed requires .7 watt/acfm to operate and a full-size ESP requires .85 watt/acfm. The retrofit ESP required at Mt. Tom is smaller than full size, and consequently a reduction in this power consumption value should be realized. Data on the power consumption of the electrofluidized bed is not available, but it must be greater than the 1.21 watt/acfm required to provide the 8" WG pressure drop.

The efficiencies offered by the electrofluidized bed and Electrified Bed retrofits are higher than could be provided with a nominally sized retrofit ESP. The numbers available for the cost of retrofit with the Electrified Bed make this technology appear economically attractive for solving the particulate pollution problems of coal combustion.

3. Middletown 3

The electrofluidized bed agglomerator and Electrified Bed were selected in Chapter IV as potential candidates for retrofit of the Middletown 3 ESP. The one-stage Electrified Bed can provide a high overall system efficiency for a capital cost of $1.00/acfm and an energy cost of .7 watt/acfm. Fan power required for the Electrified Bed is available at Middletown 3, and the pressure drop energy requirement of the collector may be provided at no cost in this application through shifting pressure presently dropped across dampers to use across the collector. The 8" WG pressure drop required by the electrofluidized bed technology cannot be provided with the present Middletown 3 fans. Consequently additional fan power for use of the electrofluidized bed would be required.

4. Mystic 7

In Chapter IV, four innovative technologies were examined with respect to their capabilities for solving the pollution control problems of a new unit burning coal. Design parameters for the innovative technologies were taken from Mystic 7. The results of the analysis are presented below for each of the technologies:

Electrofluidized Bed Collector: The electrofluidized bed collector is a potential approach for solving the utility pollution control problems of coal firing. As shown in Fig. 4.8, the system is fairly compact with respect to the 340 ft^2/1000 acfm ESP presently employed. Capital cost data for this technology is not available. Significant unknowns remain with respect to the feasibility of using a collection additive, a requirement for collector operation. Two approaches to bed particle regeneration were discussed in Section IVC (fuel oil additive with and without sintering). As reported in Table 4.1, both of these approaches are extremely energy intensive. The 14" WG pressure loss of the collector (2.15 watt/acfm), leaving aside the question of additive and particle regeneration, insures that the application of the two-stage electrofluidized bed would be extremely energy intensive. The electrofluidized bed configuration depicted in Fig. 4.8 provides no equipment for SO_2 control.

Electrified Bed, One-Stage: The one-stage Electrified Bed illustrated in Fig. 4.9 should display a high efficiency for a capital cost of $1.00 and an energy consumption of .8 watt/acfm (including .1 watt/acfm for an ionizer such as the high intensity ionizer). The capital and operating costs of the multiclone dust collector must be added to those quoted for the Electrified Bed. The Electrified Bed configuration shown in Fig. 4.9 allows no provision for SO_2 control. The capital and operating costs of the Electrified Bed appear favorable with respect to those already reported for a conventional baghouse or ESP.

Electrified Bed, Spray Dryer: The two-stage Electrified Bed illustrated in Fig. 4.10 should provide a high efficiency on coal firing and is well suited for simultaneous SO_2 control in conjunction with the spray dryer technology. The two-stage collector, exclusive of the spray dryer, can be purchased for $2.00/acfm. The energy requirement of the two-stage collector would be 1.3 watt/acfm with the rate of reprocessing doubled to handle the additional load of sulfate or sulfite salts (see Eqns. 4.1 and 4.2). The capital and operating costs of the spray dryer must be added to those already cited for the Electrified Bed. Sources quoted in Chapter IV indicate that the spray dryer technology is cost effective with respect to conventional wet scrubbing technologies for controlling SO_2 emissions.

Charged Droplet Scrubber: The charged droplet scrubber, as illustrated in Fig. 4.11, provides a potentially attractive approach for solving the combined particulates and SO_2 control problem. The electrostatic enhancement employed boosts the particulate efficiency of the collector to a level sufficient for achieving compliance with the .03 lb/MMBtu new source performance standard. Capital cost figures for the charged droplet scrubber are not yet available, since the technology has not been brought to the stage of commercialization. The energy utilization of this technology (as a particulate control device), exclusive of the requirement for plume reheat, is calculated in Chapter IV to be 4.79 watt/acfm. If plume reheat is provided through the burning of fuel, this cost will increase to 15 watt/acfm.

Electrostatically Enhanced Bag Filter: The electrostatically enhanced bag filter provides an approach to particulate control for coal fired boilers which reportedly is comparable to a conventional glass fabric filter in capital costs. The energy requirement of the electrostatically enhanced fabric filter is higher than that of a conventional baghouse, 1.41 watt/acfm compared to .76 watt/acfm. Both the conventional and electrostatically enhanced fabric filter technologies display efficiencies more than adequate for achieving the .03 lb/MMBtu new source performance standard.

5. Brayton Point 2

Four innovative technologies are examined in Chapter IV as candidates for retrofitting the present ESP. These four technologies are the electrofluidized bed collector, the electrofluidized bed agglomerator, the Electrified Bed, and the high intensity ionizer. Technologies must augment the efficiency of the present precipitator to a degree which allows a wide margin of safety for compliance with the coal conversion agreement worked out between New England Electric and the Massachusetts Department of Air and Hazardous Materials. The electrifluidized bed (both configurations) and the Electrified Bed should provide efficiency levels more than adequate for satisfying this criteria. Without the provision of an upstream particulate collector, the effectiveness of the high intensity ionizer may be insufficient to achieve compliance. Questions concerning the effectiveness of the high intensity ionizer will be answered when the first full-scale system comes on line sometime next year.

Economically, the high intensity ionizer is the most attractive of the four technologies for solving the problems at Brayton Point. Although the $1.45/acfm capital cost of the ionizer is higher than the $1.00/acfm capital cost of the one-stage Electrified Bed, this greater capital expense is offset by a lower energy requirement. The high intensity ionizer consumes just .1 watt/acfm while the one-stage Electrified Bed consumes .7 watt/acfm. At a cost for electricity of 2.9 ¢/kwhr and a 5000 hr generating year, the lower energy consumption of the high intensity ionizer compensates for the 45¢/acfm difference in capital cost in a period of 5.2 years. In addition, the ½" WG pressure requirement of the high intensity ionizer is small and could potentially be supplied by the present fans.

The 8" WG pressure requirement of both the electrofluidized bed collector and electrofluidized bed agglomerator would require that the present fans be significantly upgraded, supplemented, or replaced. The energy consumption of these two technologies is 1.21 watt/acfm for fan power, plus the unknown requirements for electrical energization, additive, and regeneration (in the case of the collector). Data is not available on the capital cost of the electrofluidized collector or agglomerator.

The 3" WG pressure drop requirement of the one-stage Electrified Bed can reportedly be supplied through an upgrading of the present ID fans. Capital and installation costs for the collector can potentially be reduced in this application below usual levels since the collection tubes can be fit within the confines of the present fan inlet boxes (see Fig. 4.15). The one-stage Electrified Bed collector is available at a capital cost of $1.00/acfm, which is less than the cost of retrofitting with additional ESP plate area (approximately $2.00/acfm). The one-stage Electrified bed accounting for the requirements of pressure drop, electrical energization, and regeneration, consumes .7 watt/acfm of electrical energy when operating. A full-scale ESP (400 SCA) requires .85 watt/acfm for operation. New England Electric personnel report that a retrofit ESP of SCA between 150 and 200 is currently under consideration for Brayton Point 2.

6. New Boston 2

Three innovative technologies are examined in Chapter IV with respect to their potential for solving the emission problems at New Boston 2 if the unit was forced to burn coal. The unit is solely equipped for oil firing at this time, and consequently is able to meet state emission standards without the use of pollution control equipment. If forced to burn coal under the provisions of the Fuel Use Act, pollution control equipment would be required to keep the emissions within the state limit of .12 lb/MMBtu for particulates and .55 lb/MMBtu for SO_2.

The two-stage electrofluidized bed collector illustrated in Fig. 4.18 provides a wide margin for compliance with the particulate emission standard but does not provide for SO_2 collection. Compliance with standards could be achieved through the use of this collector and the burning of low sulfur coal (see Sec. IVE). The two-stage collector requires 14" WG of pressure drop for operation. Consequently the employment of this technology would require the installation of ID fans. The energy requirements of the electrofluidized bed collector, beyond that for pressure drop (2.15 watt/acfm), are difficult to estimate in lieu of further development work on types of collection additives and regeneration processes. Capital cost data on the electrofluidized bed is not available since the technology has not been brought to the stage of commercialization.

The two-stage electrofluidized bed collector illustrated in Fig. 4.19 can provide a wide margin for compliance with the particulate emission limit. In conjunction with the illustrated spray dryer, SO_2 emissions can be controlled and a wider variety of fuel sulfur contacts can be utilized. The capital cost of the two-stage Electrified Bed collector is $2.00/acfm (including auxiliary equipment), and the energy consumption while operating is 1.3 watt/acfm (including the fan pressure drop cost and the requirement for handling the additional dust load due to the spray dryer). The 6" WG pressure requirement of the two-stage Electrified Bed must be supplied through the installation of ID fans, since excess capacity is not available from the present FD fans. The spray dryer collection system is reportedly an attractive technique for controlling SO_2 emissions (see Sec. IVC).

The capabilities of the wet electrostatic precipitator for combined particulates and SO_2 control make this technology attractive for employment at New Boston. The four collectors illustrated in Fig. 4.20 were sized to marginally comply with state particulate emission limitations. Data is not available at this time for predicting the effectiveness of the collector in controlling SO_2 emissions, although EPA test results should be available soon. The capital cost of the collector, exclusive of equipment required for SO_2 control and water treatment, is $5.47/acfm. Although extra pressure drop is not presently available on the unit, the 1" WG required for the Fluid-Ionic collector might be available on coal firing due to the lower required flue gas flowrate. Exclusive of plume reheat, water handling, and SO_2 control equipment, the wet electrostatic precipitator consumes .46 watt/acfm of energy. If plume reheat is provided through the combustion of oil, energy consumption for the collector (exclusive of water handling and SO_2 control equipment) climbs to 10.72 watt/acfm. As suggested in

Fig. 4.20 plume reheat could presumedly be provided from a source less expensive than direct fuel consumption (if the SO_2 collection efficiency of the wet collector is more than adequate for achieving the state emission standard, plume reheat can be provided through bypassing a portion of the flue gas around the collector).

In lieu of a requirement for SO_2 control the conventional electrostatic precipitator and the two-stage Electrified Bed provide competitive techniques for achieving the particulate emission standard. The capital cost of the two-stage collector is \$2.00/acfm, and a wide margin of extra efficiency is provided which is not affected by coal sulfur content (in the Electrified Bed corona current is not forced through a collected ash layer). A moderately sized electrostatic precipitator can be purchased for a capital cost of \$2.00/acfm (an SCA of approximately 260 ft^2/1000 acfm), but a larger collector would be required for use on low sulfur coal. The energy requirement of both collectors is approximately .7 watt/acfm. Difficulties can be envisioned for installation of a large ESP in the space available at New Boston (see Fig. 4.17), since ducting must be extended around the collector to achieve a gas entrance direction from the north (from the left on Fig. 4.17).

In the event that SO_2 control is required capital and operating costs will be dominated by the expense incurred for SO_2 collection. Although the dry collection system at this point in time seems to be a more attractive approach than wet collection, the first full-scale unit will not be operating until 1980. At that time the claims made by promoters of the dry technology can be more closely examined. The dry collection technology can be employed in conjunction with either a baghouse, electrostatic precipitator, or the Electrified Bed. The space limitations at New Boston rule out employment of a baghouse collector. The electrostatic precipitator does not allow for as high of a reagent utilization as can be achieved by the baghouse or hypothetically by the Electrified Bed. Pilot plant testing of the combined spray dryer and granular bed technologies is scheduled to occur within the next several months at EFB, Incorporated in Woburn, Massachusetts. At this preliminary stage the combination of these two technologies appears attractive for solving the problems at New Boston.

C. BIBLIOGRAPHY

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APPENDIX A. Benchmark Standard Development

Research work at MIT has long focused on small particles because they are difficult to collect and because of their greater toxicity. Other arguments for fine particle control center around their long atmospheric residence time and resulting effect on visibility. Particulate standards are currently blind to particle size and properties. As research work in environmental sciences progresses, standards will focus more on the specific toxicity and welfare effects of emissions. Therefore, a broad survey of not only legislation but current research must be conducted in order to develop farsighted scenarios.

A standard based on submicron emissions seems unlikely at this time. Although submicron material may be the most toxic and persistent, atmopheric submicron material is for the most part secondary. Secondary material is formed in the atmosphere from gas phase pollutants, and is more effectively controlled through the regulation of gas phase mateirals. The Health Effects Research Lab (HERL) of EPA has recently proposed that a standard based on particles of less than 15 μm diameter (inhalable particulate) be enacted, and that monitoring and health data be gathered for consideration of a "fine particle" standard. Fine particles would be defined as material with a diameter of less than 2.5 μm. A standard based on particles of less than 2.5 μm is feasible from the standpoint of design for reliable monitoring instruments, and would effectively identify the lower mode of the atmospheric bimodal particle size distribution. Particles in the lower atmospheric mode are generally either secondary or are formed from condensation processes. Upper mode particles consist primarily of entrained dust, although flyash emitters can contribute to this mode. Lower mode particles have much longer atmospheric residence times than larger particles, and therefore control of sources for these particles can yield measurable atmospheric results.

The revised new source performance standard provides the keystone by which foreseeable performance standards can be estimated. This standard, arrived at through extensive study by the EPA is mandated to reflect a standard consistent with "the best system of continuous emission reduction." The new source performance standard promulgated in June, 1979 dictates an emission level of below .03 lb/MMBtu (13 ng/J) and a minimum reduction level of 70% for liquid fuels and 99% for solid fuels. Emission reduction levels are not controlling since typical emission factors are assumed for all units and testing is not to be performed at the inlets of emission control systems. This new source performance standard (NSPS) is the standard by which other control classifications: RACT, BACT, LAER, and BART, will be evaluated. While RACT and BART should be less stringent than the NSPS, BACT and LAER must be equal or more stringent. While only RACT and BART can be applied to existing sources, it seems prudent for the purpose of this study to translate the total mass NSPS standard into an equivalent standard for particles smaller than 2.5 μm. The work presently under way at HERL could lead to the use of probes with cut diameters of 2.5 μm, so this translation should be considered not altogether arbitrary.

The extent to which the NSPS standard of .03 lb/MMBtu (13ng/J) impinges on fine particle emissions can be judged by numerically integrating the product of a typical size distribution resulting from coal combustion with the Deutsch equation, representing the effect of an ESP on the resulting particulate size. Particle charge is estimated from the field charging equation which yields a linear dependence between particle size and mobility. The overall efficiency of the system is set to just achieve the NSPS.

TABLE A.1

CONTROL LEVEL REQUIRED ON COAL EMISSIONS TO MEET THE NSPS.

Case Study	A	B
Coal heat value (Btu/lb)	13,000	12,000
(kJ/gm)	(30.2)	(27.8)
Coal ash content (%)	8%	22%
Uncontrolled emission rate (lb/MMBtu) (4 to 1 ratio of fly ash to bottom ash)	4.92	14.6
(ng/J)	(2126)	(6325)
Uncontrolled efficiency required to meet NSPS (%)	99.39%	99.79%

$$f(\log d) = \frac{1}{\sqrt{2\pi}\,\log \sigma_g} \exp\left[\frac{-(\log d - \log d_g)^2}{2\log^2 \sigma_g}\right] \qquad \text{A.1}$$

$$\frac{M_{out}}{M_{in}}(d) = \exp\left[\frac{-\tau_{res}\,E^2\varepsilon_o d}{s\mu}\right] \qquad \text{A.2}$$

(The lognormal particle size distribution and the ESP transfer function incorporating the field charging model are represented by equations A.1 and A.2 respectively.)

Two sets of coal properties are chosen for analysis. The size distribution of coal emissions is taken from "A Manual of Electrostatic Precipitator Technology". The size distribution for the emissions of both coals is taken as lognormal with a mass median diameter of 13 μm and a geometric standard deviation of 3.31. Table A.1 gives the coal characteristics and the overall efficiencies required to meet the NSPS.

The integrated lognormal function always equals one as shown in Eq. A.3.

$$\int_{d=0}^{d=\infty} \frac{1}{\sqrt{2\pi}\,\log\sigma_g} \exp\left[\frac{-(\log d - \log d_g)^2}{2\log^2\sigma_g}\right] \frac{d(d)}{2.303\,d} = 1 \qquad \text{A.3}$$

Where d(logd) = d(d)/2.303d. The fraction of the inlet meaterial leaving the ESP can be found by Eq. A.4.

$$\frac{M_{out}}{M_{in}} = \int_{d=0}^{d=\infty} \frac{M_{out}}{M_{in}}(d)\ f(\log d)\ \frac{d(d)}{2.303d} \qquad \text{A.4}$$

This equation is approximated as a sum for numerical integration in Eq. A.5.

$$\frac{M_{out}}{M_{in}} = \sum_{x=1}^{\infty} \frac{M_{out}}{M_{in}}\ (\frac{x}{10}) f(\log \frac{x}{10})\ \frac{1}{2.303x} \qquad \text{A.5}$$

In order to achieve the ESP efficiencies cited in Table A.1 a minimum ESP size characterized by the parameter $\tau_{res}E^2\varepsilon_0/s_\mu$ must be found. This parameter is the product of precipitator SCA (τ_{res}/s) and several independent constants ($E^2\varepsilon_0/\mu$). The value of this parameter which achieves the NSPS for the two case studies is listed in Table A.2.

TABLE A.2

VALUES FOR ESP PARAMETER TO ACHIEVE NSPS

CASE STUDY	$\tau_{res}\ E^2\varepsilon_0{}' s\mu$ (1/μm)
A	2.2
B	3.64

Numerical integration of Eq. A.5 with the ESP parameter values listed in Table A.2 yields an emission equivalent to 0.03 lb/MMBtu (13ng/J) for case studies A and B. This emission level is the new proposed NSPS. Examination of the output size distribution for case A shows that only 1.4% of the material emitted is larger than 2.5 μm, and for case B only .06% of the material emitted is larger than 2.5 μm. This result implies that the employment of a sampling probe with a cut diameter of 2.5 μm will serve primarily to exclude reentrained material. These larger particles upon leaving the stack should settle on their own accord, and not contribute to the problems uniquely attributed to smaller particles (accentuated health effects and reductions in atmospheric visibility). Larger particles might continue to be regulated in the future under the less stringent welfare-related NAAQS secondary standard. The use of a mechanical collector would only marginally contribute to achieving this standard since its effectivenes is restricted to large particles.

The previous analysis has demonstrated that an emission standard of .03 lb/MMBtu (13ng/J) for particles below 2.5 μm is equivalent to the NSPS proposed in September, 1978 for typical coal emissions, with the exception that reentrained material larger than 2.5 μm is excluded from the sampling.

Since 8% of the emissions are below 2.5 μm, this standard requires a control efficiency for particles smaller than 2.5 μm of 92.5% for case study A and 97.4% for case study B. The standard of .03 lb/MMBtu for particles smaller than 2.5 μm is referred to as the benchmark standard throughout this study.

A standard of .03 lb/MMBtu (13 ng/J) for particles below 2.5 μm can be evaluated for different particulate emission characteristics and control systems through numerical integration. This standard would be satisfied if the condition of Eq. A.6 is met.

$$\Gamma\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \sum_{x=1}^{25} \frac{M_{out}}{M_{in}} \left(\frac{x}{10}\right) (0.1) \leqq .03 \left(\frac{\text{lb}}{\text{MMBtu}}\right) \qquad \text{A.6}$$

Γ ≡ Emission level for particulate entering unit under evaluation

$f(d)$ ≡ Particle size distribution function normalized to unity for integral over all particle sizes (μm)

$\frac{M_{out}}{M_{in}}(d)$ ≡ Emission control transfer function (μm)

This constraint can be tested for a case study C based on oil-fired emissions. The data of Brummer is utilized, and is reported in Chapter II, Section A of the report. Using the same ESP transfer function A.2, it will be interesting to compare the ESP parameter necessary to comply with Eq. A.6 for oil emissions with the parameters reported in Table A.2 for control of coal emissions.

Brummer reports that with 1% excess air, an oil-fired unit burning 2.45%S oil has a total emission rate of 0.15 lb/MMBtu (65 ng/J). The particle size distribution given by Brummer is reported in Table A.3.

TABLE A.3

OIL EMISSION PARTICLE SIZE DISTRIBUTION

Size Range (μm)	% in range
less than .48	36
.48 - .71	8
.72 - 1.15	9
1.16 - 2.3	4
2.4 - 3.6	11
3.7 - 5.2	5
5.3 - 7.8	15
7.9 -12.5	4
greater than 12.5	8

Solution of Eq. A.6 for the particle size distribution of Table A.3 reveals that for case study C the ESP parameter necessary to achieve the NSPS is $\tau_{res}E^2\varepsilon_o/s\mu = 3$ (1/μm). This calculation reveals that the precipitator size required to achieve the benchmark standard for C (oil) is between that required to achieve case studies A and B (coal).

Innovative hardware performance will be judged with respect to the benchmark .03 lb.MMBtu (13ng/J), smaller than 2.5 μm standard as well as other standards of significance to the particular plants as discussed in Chapter IV.

APPENDIX B. Conversion of Stack Emissions from per Heat Release to per Volume

Regulations which govern emissions from smokestacks have traditionally been normalized by process parameters. In the case of many processes, emissions are permitted as a function of raw material feedrate. In the case of steam boilers, emissions are generally permitted proportional to the plant heat input rate.

Specifying plant emissions normalized by the heat input rate has been an almost universally accepted practice since air pollution emission standards originated. With this regulation format, a plant's uncontrolled emission rate and required efficiency to meet the standard can be closely estimated when burning coal from the fuel analysis alone. This format has the additional advantage that it is representative of public health interests since large sources generally have greater dispersion through enhanced plume rise and the use of higher smokestacks.

The uncontrolled emission rate from coal firing can be estimated from the fuel analysis through the use of several assumptions. This is possible since the particulate emission from coal firing is primarily ash, although from some boilers the carbon content of ash can run as high as 10%. With good combustion, the carbon content of ash can be approximated as negligible. Another commonly used approximation is that the ratio of flyash to bottom ash is four to one. This ratio will increase for a cyclonic fired boiler, and should be evaluated for each boiler from the collected ash. An approximate value for uncontrolled emission from coal firing is provided by Eqn. B.1.

$$\frac{M_{ash} \cdot FAF \cdot 10^6}{HC} = UE \qquad B.1$$

HC ≡ heat content of fuel (Btu/lb)

M_{ash} ≡ ash content as function of fuel weight

FAF ≡ fraction of ash which becomes flyash (~.8)

UE ≡ uncontrolled emissions (lb/MMBtu)

In order to calculate the efficiency required to achieve the .03 lb/MMBtu new source performance standard Eqn. B.2 can be employed.

$$\eta = 1 - \frac{.03}{UE} \qquad B.2$$

η ≡ efficiency

This simplification cannot be utilized for oil firing since the particulate emissions are dominated by non-ash components such as sulfates and carbon. Sulfate emission is unique to oil combustion due to the presence of vanadium catalyst.

The recently promulgated new source performance standard for sulfur dioxide emissions provides the first notable exception to the regulation of emissions by the measure of mass per heat input. A percentage reduction with respect to potential emissions is required in order to encourage the utilization of local coal reserves (see Sec. IB3 on new source performance standards).

The efficiency of pollution control equipment is a function of gas flowrate, and operation is often dependent on gas grain loading. These quantities can be calculated with knowledge of the ultimate fuel analysis and furnace excess air rate. An ultimate fuel analysis of coal will provide the following breakdown of fuel content.

$$M_C + M_H + M_O + M_S + M_{H_2O} + M_N + M_{ash} = 1 \qquad \text{B.3}$$

M_C ≡ fuel carbon content
M_H ≡ fuel hydrogen content (not water)
M_O ≡ fuel oxygen content (not water)
M_S ≡ fuel sulfur content
M_{H_2O} ≡ fuel water content
M_N ≡ fuel nitrogen content

In addition, the fuel heat content is generally supplied. Due to the high temperatures employed in powerplant boilers, complete combustion of the fuel is a valid assumption. Complete combustion implies that all carbon is converted to carbon dioxide and all hydrogen is converted to water. It is assumed that sulfur is completely combusted to sulfur dioxide and fixed nitrogen is converted to free nitrogen except for a percentage which is converted to nitrogen dioxide. The nitrogen dioxide formation rate is generally dependent on combustion and fuel properties. An average value is taken for this calculation from AP-42. The emission rate of materials in the boiler plume is given by equations B.4 through B.10.

$$E_{SO_2} = 2\ M_S \qquad \text{B.4}$$

$$E_{CO_2} = \frac{11}{3}\,(M_C - E_C) \qquad \text{B.5}$$

$$E_{NO_2} = .009 \text{ (from AP-42)} \qquad \text{B.6}$$

$$E_{H_2O} = M_{H_2O} + 9\ M_{H_2} \qquad \text{B.7}$$

$$E_{solids} = FAF \cdot M_{ash} + E_C \qquad \text{B.8}$$

$$E_{O_2} = (.23)\ AI \cdot x/(1+x) \qquad \text{B.9}$$

$$E_{N_2} = (.77)\ AI + M_{N_2} - .009(7/23) \qquad \text{B.10}$$

E_a ≡ emission rate of constituent a in lb/(lb fuel consumed)

AI ≡ air intake in lb/(lb fuel consumed)

x ≡ ratio of excess to stoichiometric air

E_C ≡ emission of unburned carbon solids lb/(lb fuel consumed)

Equations B.4 through B.10 are based on the engineering approximation that air consists of 23% O_2 and 77% N_2 by weight (this is equivalent to 21% O_2 and 79% N_2 by volume).

An expression for stoichiometric furnace oxygen demand is provided as Eqn. B.11.

$$OD = \frac{8}{3}(M_C - E_C) + M_S + 8M_H + (.009 \cdot \frac{16}{23}) - M_{O_2} \qquad \text{B.11}$$

OD ≡ oxygen demand (lb/lb fuel consumed)

The following approximate molecular weights are utilized for all calculations.

Species	Molecular Weight $(\frac{gm}{mole})$
N	14
O	16
H	1
S	32
C	12

Boiler air intake is calculated by Eqn. B12.

$$AI = OD \frac{1+x}{.23} \qquad \text{B.12}$$

AI ≡ air intake (lb/lb fuel consumed)

The total gas volume leaving the boiler can be calculated from the ideal gas law and the provided expressions. The resulting gas volume is referenced to air which occupies 12.42 ft^3/lb at STP and displays an average molecular weight of 29 gm/mole. Equation B.13 gives the flue gas volume per pound of fuel at 0°C and 760 mm Hg (STP).

$$V_{STP}\left(\frac{ft^3}{lb\ fuel}\right) = 12.42\ \frac{ft^3}{lb\ air}\left[\frac{29}{64}E_{SO_2} + \frac{29}{44}E_{CO_2} + \frac{29}{46}E_{NO_2} + \frac{29}{18}E_{H_2O} + \frac{29}{32}E_{O_2} + \frac{29}{28}E_{N_2}\right] \qquad B.13$$

The gas exit volume at 300°F stack gas temperature and 760 mm Hg is given by Eqn. B.14.

$$V_{300°F,atm}\left(\frac{ft^3}{lb\ fuel}\right) = V_{STP}\cdot\frac{149°C + 273°C}{273°C} \qquad B.14$$

The gas grain loading at 300°F is shown as Eqn. B.15.

$$L\left(\frac{gr}{aft^3}\right) = \frac{E_{solids}\ 7000\ gr/lb}{V_{300°F,atm}} \qquad B.15$$

The fuel consumption of a powerplant can be calculated from the plant heat rate and power production rate. Equation B.16 provides an expression for plant fuel consumption.

$$FC\left(\frac{lb}{hr}\right) = PHR\left(\frac{Btu}{kwh}\right)\cdot PROD(MW)\cdot 1000\frac{kw}{MW}\cdot\frac{M_C}{M_C-E_C}\cdot\frac{1}{HC\left(\frac{Btu}{lb}\right)} \qquad B.16$$

FC ≡ plant fuel consumption (lb/hr)

PHR ≡ effective plant heat rate (≈ 10,000 Btu/kwh)

PROD ≡ electric power production (MW)

Equations B.17 and B.18 give the plant exit flowrate in both standard cubic feet per minute and actual cubic feet per minute.

$$\text{FLOW(scfm)} = V_{STP}\ \text{FC(lb/hr)} \cdot .0167\text{(hr/min)} \tag{B.17}$$

$$\text{FLOW(acfm)} = V_{300°\text{F,atm}}\ \text{FC(lb/hr)} \cdot .0167\text{(hr/min)} \tag{B.18}$$

Design data from the Middletown 3 boiler provides an opportunity for evaluation of the preceding expressions. Ultimate analysis of the design coal and approximate operating parameters for the cyclone fired boiler are given below.

HC = 13,230 Btu/lb
$M_O = .062$
$M_N = .016$
$M_{H_2O} = .034$
$M_C = .716$
$M_H = .051$
$M_S = .029$
$M_{ash} = .092$
FAF ≈ .6
PHR ≈ 10,000 Btu/kwh
PROD = 240 MW
$x = .16$
$E_C \approx 0$

Table B.1 shows the values which result from substituting the above Middletown 3 parameters into equation B.1 through B.18. Note that from Eqn. B.4 the SO_2 emission rate can be calculated, and for this example the SO_2 emission rate would be 4.38 lb/MMBtu.

TABLE B.1

Middletown 3 Operating Parameters

Quantity Derived	Equation Which Gives Value	Answer
UE	B.1	4.17 lb/MMBtu
η	B.2	99.3%
E_{SO_2}	B.4	.058 lb/lb fuel
E_{CO_2}	B.5	2.625 lb/lb fuel
E_{NO_2}	B.6	.009 lb/lb fuel
E_{H_2O}	B.7	.493 lb/lb fuel
E_{solids}	B.8	.0552 lb/lb fuel
E_{O_2}	B.9	.367 lb/lb fuel
E_{N_2}	B.10	8.91 lb/lb fuel
OD	B.11	2.29 lb/lb fuel
AI	B.12	11.56 lb/lb fuel
V_{STP}	B.13	150.5 sft^3/lb fuel
$V_{300°F,atm}$	B.14	233 aft^3/lb fuel
L	B.15	1.66 gr/aft^3
FC	B.16	181,406 lb/hr
FLOW (scfm)	B.17	455,026 scfm
FLOW (acfm)	B.18	704,460 acfm

APPENDIX C. Metric Conversion Factors

To convert from	To	Multiply by*
	Length	
Inches (in)	Meter	2.540 000 E-02
Feet (ft)	Meter	3.048 000 E-01
Yards (yd)	Meter	9.144 000 E-01
	Area	
Square feet (ft^2)	Square meters (m^2)	9.290 304 E-02
Square yards (yd^2)	Square meters (m^2)	8.361 274 E-01
Acres	Square meters (m^2)	4.046 873 E+03
	Volume	
Liters	Cubic meters (m^3)	1.000 000 E-03
Gallon (U.S. Liquid)	Cubic meters (m^3)	3.785 412 E-03
Cubic feet (ft^3)	Cubic meters (m^3)	2.831 685 E-02
Cubic yards (yd^3)	Cubic meters (m^3)	7.645 549 E-01
Barrels (oil, 42 gal)	Cubic meters (m^3)	1.589 873 E-01
Acre-feet	Cubic meters (m^3)	1.233 486 E+03
	Mass	
Grams (g)	Kilogram (kg)	1.000 000 E-03
Ounces (oz)	Kilogram (kg)	2.834 952 E-02
Pounds (lb)	Kilogram (kg)	4.535 924 E-01
Tons (metric)	Kilogram (kg)	1.000 000 E+03
Tons (short)	Kilogram (kg)	9.071 847 E+02
	Energy	
BTUs (international)	Joule (j)	1.055 056 E+03
Calories (international)	Joule (j)	4.186 800 E+00
Ergs	Joule (j)	1.000 000 E-07
Kilocalories (international)	Joule (j)	4.186 800 E+03
	Energy/Mass	
BTU/LB	Joules/kilogram (j/kg)	2.326 000 E+03
BTU/Ton (short)	Joules/kilogram (j/kg)	1.163 000 E+00
	Power (Energy/Time)	
BTU/second (sec)	Joules/sec (watt)	1.055 056 E+03
BTU/minute (min)	Joules/sec (watt)	1.758 426 E+01
BTU/hour (hr)	Joules/sec (watt)	2.930 711 E-01
	Volume/Time	
Gal/second (sec)	Cubic meters (m^3)/sec	3.785 412 E-03
Gal/minute (min)	Cubic meters (m^3)/sec	6.309 020 E-05
Gal/hour (hr)	Cubic meters (m^3)/sec	1.051 503 E-06
Gal/day	Cubic meters (m^3)/sec	4.381 263 E-08
Barrels/day	Cubic meters (m^3)/sec	1.840 130 E-06

APPENDIX D, Acronyms, Expansion of.

APCA	Air Pollution Control Association
APCD	Air Pollution Control District
AQCR	Air Quality Control Region
BACT	best available control technology
BART	best available retrofit technology
BECO	Boston Edison Co.
CAA	Clean Air Act
CDS	charged droplet scrubber
CT	Connecticut
DAHM	Department of Air and Hazardous Materials (MA)
DEP	Department of Environmental Protection (CT)
DEQE	Department of Environmental Quality Engineering (MA)
EEBF	electrostatically enhanced bag filter
EFB	electrofluidized bed
EFB, Inc.	promoters of Electrified Bed (Woburn, MA)
EIS	Environmental Impact Statement
ElB	Electrified Bed
EPA	Environmental Protection Agency
ERA	Economic Regulatory Administration
ERT	Environmental Research and Technology, Inc.
ESECA	Energy Supply and Environmental Coordination Act
ESP	electrostatic precipitator
FGD	flue gas desulfurization
FUA	Fuel Use Act (Powerplant and Industrial . . .)

HERL	Health Effects Research Lab (EPA)
HII	high intensity ionizer
LAER	lowest achievable emission rate
MA	Massachusetts
MMBtu	million British thermal units heat input
MTDC	Massachusetts Technology Development Corp.
NAAQS	national ambient air quality standards
NAS	National Academy of Science
NEDS	National Emissions Data System
NEPCO	New England Power Co.
NEU	Northeast Utilities
NRDC	Natural Resources Defence Council
NSPS	new source performance standard
O&M	operation and maintenance
PO	prohibition order (under ESECA)
PSD	prevention of significant deterioration
S&A	Surveillance and Analysis (EPA)
SIP	state implementation plan
TSP	total suspended particulate
UARG	Utility Air Regulatory Group
WESP	wet electrostatic precipitator
WG	water gauge (pressure drop measurement)